89-1988
No. ———

In The
Supreme Court of the United States
October Term, 1989

The Berkshire Gas Co., *et al.*,
Petitioners,
v.
Associated Gas Distributors, *et al.*,
Respondents.

Tennessee Small General Service Customer Group, *et al.*,
Petitioners,
v.
Associated Gas Distributors, *et al.*,
Respondents.

National Fuel Gas Supply Corporation,
Petitioner,
v.
Associated Gas Distributors, *et al.*,
Respondents.

JOINT APPENDIX TO PETITIONS FOR WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

John W. Glendening, Jr.
Barbara K. Heffernan
Counsel of Record
Cheryl L. Jones
Schiff, Hardin & Waite
1101 Connecticut Ave., N.W.
Washington, D.C. 20036
Attorneys for The Berkshire Gas Co., et al.

Michael J. Manning
Counsel of Record
James F. Moriarty
Fulbright & Jaworski
1150 Connecticut Ave., N.W.
Suite 400
Washington, D.C. 20036
Attorneys for Tennessee Small General Service Customer Group

(Attorneys Continued on Inside Cover)

Wilson - Epes Printing Co., Inc. - 789-0096 - Washington, D.C. 20001

JAMES F. BOWE, JR.
O. JULIA WELLER
HUNTON & WILLIAMS
P.O. Box 19230
Washington, D.C. 20036

JEFFREY L. FUTTER
Long Island Lighting Company
175 East Old Country Road
Hicksville, NY 11801

Attorneys for
Long Island Lighting Company

WILLIAM J. CRONIN
JONATHAN D. SCHNEIDER
HUBER, LAWRENCE & ABELL
99 Park Avenue
New York, NY 10016

Attorney for
New York State Electric & Gas Corporation

DAVID L. KONICK
CULLEN AND DYKMAN
1225 19th Street, N.W.
Washington, D.C. 20036

Attorney for
The Brooklyn Union Gas Company

JAMES R. CHOUKAS-BRADLEY
DEMETRIOS G. PULAS, JR.
MILLER, BALIS & O'NEIL, P.C.
1101 14th Street, N.W.
Suite 1400
Washington, D.C. 20005

Attorneys for
Cities of Clarksville, Springfield, and Portland, Tennessee, and Humphreys County Utility District, Tennessee

DAVID B. WARD
ALLAN W. ANDERSON, JR.
FLOOD & WARD
1000 Potomac Street, N.W.
Suite 402
Washington, D.C. 20007

Attorneys for
Western Kentucky Gas Company, A Division of Atmos Energy Corp.

GEORGE L. WEBER
Counsel of Record
KENNETH L. GLICK
WEBER & ASSOCIATES, P.C.
727 Fifteenth Street, N.W.
Tenth Floor
Washington, D.C. 20005

RICHARD M. DIVALERIO
Secretary and General Counsel
NATIONAL FUEL GAS SUPPLY CORPORATION
10 Lafayette Square
Buffalo, NY 14203

Attorneys for
National Fuel Gas Supply Corporation

JOINT APPENDIX
TABLE OF CONTENTS

	Page
APPENDIX A	
Opinion of the Court of Appeals	1a
APPENDIX B	
Denial of Rehearing and Suggestions for Rehearing *En Banc*	29a
APPENDIX C	
Order of Court of Appeals Staying Its Mandate	35a
APPENDIX D	
Initial Decision of the Commission's Presiding Administrative Law Judge	37a
APPENDIX E	
Initial Opinion of the Federal Energy Regulatory Commission	94a
APPENDIX F	
Opinion on Rehearing of the Federal Energy Regulatory Commission	132a
APPENDIX G	
Addendum to Petition of Commission for Rehearing and Suggestion for Rehearing *En Banc*	171a
APPENDIX H	
Separate Statement of Chief Judge Wald in *Transwestern Pipeline Company v. Federal Energy Regulatory Commission*	192a
APPENDIX I	
Commission's Motion for Stay of Mandate Pending Application for a Writ of Certiorari	195a
APPENDIX J	
List of Parties to Proceeding Before Court of Appeals	201a

APPENDIX A

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued October 30, 1989 Decided December 28, 1989

No. 88-1385

ASSOCIATED GAS DISTRIBUTORS,
Petitioner

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

THE PEOPLES GAS LIGHT & COKE CO., *et al.*,
Intervenors

and consolidated case Nos. 88-1386, 88-1387, 88-1388, 88-1389, 88-1390, 88-1393, 88-1400, 88-1406, 88-1421, 88-1452, 88-1459, 88-1460, 88-1461, 88-1462, 88-1463, 88-1502, 88-1503, 88-1512, 88-1524, 88-1534, 88-1535, 88-1536, 88-1538, 88-1560, 88-1565, 88-1568, 88-1598, 88-1616, 88-1624, 88-1638, 88-1642, 88-1655, 88-1656, 88-1695, 88-1766, 89-1165, 89-1218, 89-1279 & 89-1303.

Petitions for Review of Orders of the
Federal Energy Regulatory Commission

Timothy N. Black and *Jennifer N. Waters* with whom *Frederick Moring*, *Toni M. Fine*, for Associated Gas Distributors; *John H. Pickering*, *Gary D. Wilson*, *Neal T.*

Kilminster, Stephen J. Small, Mark D. Clark, for Columbia Gas Transmission Corporation; *Ronald N. Carroll* for The Inland Gas Company, Inc.; *Stanley M. Morley, Paul W. Diehl,* for Alabama-Tennessee Natural Gas Company; *Robert F. Shapiro, Thomas E. Hirsch, III,* for American Paper Institute; *Lynne H. Church, Robert Fleishman, Jeffrey D. Watkiss,* for Baltimore Gas and Electric Company; *Roberta L. Halladay, Marilyn A. Specht,* for Connecticut Natural Gas Corporation; *Stephen E. Williams, Henry E. Brown, Kevin J. Lipson, Charles C. Thebaud, Jr.,* for CNG Transmission Corporation; *Roger C. Post, John L. Shailer,* for Columbia Gas Distribution Companies; *William I. Harkaway, Harvey L. Reiter, Barbara M. Gunther,* for Consolidated Edison Company of New York; *Veronica Smith, John F. Povilaitis,* for Pennsylvania Public Utilities Commission; *Thomas M. Patrick, Karen Lee,* for The Peoples Gas Light and Coke Company; *Kevin J. McKeon,* for The Peoples Natural Gas Company; *Edward J. Grenier, Jr., William H. Penniman* and *James M. Bushee,* for The Process Gas Consumers Group and The American Iron and Steel Institute; *Richard A. Solomon, David D'Alessandro,* for Public Service Commission of the State of New York; *James R. Lacey* and *William R. Hoatson,* for Public Service Electric and Gas Company; *Frank H. Strickler, Gordon M. Grout* and *Ralph E. Fisher,* for Washington Gas Light Company were on the initial joint brief, for certain petitioners and intervenors in support of petitioners in opposition to orders under review.

Gary E. Guy with whom *Augustine A. Mazzei, Jr.,* and *Joseph P. Stevens* were on the initial brief, for petitioner, Equitable Gas Company.

Susan D. McAndrew with whom *John H. Pickering, Timothy N. Black, Gary D. Wilson, Stephen J. Small* and *Mark D. Clark,* were on the brief, for RP83-8 and CP84-441 payments in Tennessee's purchase deficiency allocation method for Columbia Gas Transmission Corporation.

Joel M. Cockrell, Attorney, Federal Energy Regulatory Commission, with whom *Catherine C. Cook*, General Counsel, *Jerome M. Feit*, Solicitor, and *Jill Hall*, Attorney, Federal Energy Regulatory Commission were on the brief, for respondent.

Barbara K. Heffernan with whom *John W. Glendening, Jr., Bruce B. Glendening, Thomas M. Preston*, for The Beckshire Gas Company, *et al.*; *Harry H. Voigt, M. Reamy Ancarrow, Mindy A. Buren, Diane B. Schratwieser, Erward B. Myers*, for Niagara Mohawk Power Corporation and Orange and Rockland Utilities, Inc.; *Ronald N. Carroll, L. Michael Bridges*, for Inland Gas Company; *Donald K. Dankner, Frederick J. Killion*, for Central Hudson Gas and Electric Corporation; *Kevin J. Lipson, John E. Holtzinger, Jr.*, for CNG Transmission Corporation; *John H. Pickering, Timothy N. Black, Neal T. Kilminster, Stephen J. Small* and *Mark D. Clark*, for Columbia Gas Transmission Corporation; *William J. Cronin, Jonathan D. Schneider*, for New York State Electric and Gas Corporation, *James R. Choukas-Bradley, Demetrios G. Pulas, Jr.*, for Cities of Clarksville, Portland, and Springfield, Tennessee and Humphreys County Utility District, Tennessee, *Michael J. Manning, James F. Moriarty, James P. White*, for Tennessee Small General Service Customer Group; *David B. Ward, Allan W. Anderson, Jr.*, for Western Kentucky Gas Company were on the joint briefs, for certain intervenors, distribution companies and natural gas pipeline companies in support of Federal Eenrgy Regulatory Commission.

Robert H. Benna with whom *Robert G. Kern, Terence J. Collins, David D. Withnell* and *Margaret L. Bollinger* were on the brief in support of Federal Energy Regulatory Commission for Tennessee Gas Pipeline Company.

Robert H. Benna with whom *John T. Ketcham, David D. Withnell, Terence J. Collins* and *Margaret L. Bollinger* were on the brief, for petitioner, Tennessee Gas Pipeline Company.

Joshua L. Menter was on the brief, for petitioner, North Penn Gas Company.

George L. Weber and *Kenneth L. Glick* were on the brief addressing the "base period" issue for petitioner, National Fuel Gas Supply Corporation.

Lynne H. Church, Robert Fleishman, Jeffrey D. Watkiss for Baltimore Gas and Electric Company; *William I. Harkaway, Harvey L. Reiter, Barbara M. Gunther*, for Consolidated Edison Company of New York, Inc.; *Donald K. Dankner, Frederick J. Killion*, for Central Hudson Gas and Electric Corporation; *John H. Pickering, Timothy N. Black, Gary D. Wilson, Neal T. Kilminster, Stephen J. Small, Mark D. Clark*, for Columbia Gas Transmission Corporation; *Roberta L. Halladay, Marilyn A. Specht*, for Connecticut Natural Gas Corporation; *Gary E. Guy*, for Equitable Gas Company; *James J. Stoker, III, Arnold H. Quint, James F. Bowe, Jr., O. Julia Weller*, for Long Island Lighting Company; *George L. Weber*, for National Fuel Gas Supply Corporation; *William J. Cronin, Jonathan D. Schneider*, for New York State Electric and Gas Corporation; *Margaret Ann Samuels, Joseph P. Serio*, for Office of Consumers' Counsel, State of Ohio; *Glenn W. Letham, Kenneth M. Albert*, for Pennsylvania Gas and Water Company; *Edward J. Grenier, Jr., James M. Bushee*, for Process Gas Consumers Group and the American Iron and Steel Institute; *Richard A. Solomon, David D'Alesandro*, for Public Service Commission of the State of New York were on the joint brief, for petitioner, Consolidated Edison Company of New York, Inc., and certain intervenors on "sunset date" and "litigation exception" issues.

Richard A. Solomon and *David D'Alessandro*, for The Public Service Commission of the State of New York; *Margaret Ann Samuels* and *Joseph P. Serio*, for The Office of Consumers' Counsel, State of Ohio; *Jeffrey D. Watkiss, Lynne E. Church, Robert Fleishman*, and *Dan R. Skowronski*, for Baltimore Gas and Electric Company;

John F. Povilaitis, Daniel P. Delaney and *Veronica Smith*, for The Pennsylvania Public Utility Commission; *John L. Shailer* and *Roger C. Post*, for Columbia Gas of Kentucky, Inc., *et al.*; *William I. Harkaway, Harvey L. Reiter* and *Barbara M. Gunther*, for Consolidated Edison Company of New York; *Glenn W. Letham* and *Kenneth M. Albert*, for Pennsylvania Gas and Water Company; *John M. Glynn* and *Paul S. Buckley*, for Maryland Peoples Counsel; *George L. Weber*, for National Fuel Gas Supply Corporation; *Gary E. Guy*, for Equitable Gas Company; *O. Julia Weller*, for Long Island Lighting Company; *Frank H. Strickler, Gordon M. Grant* and *Ralph E. Fisher*, for Washington Gas Light Company were on joint petitioners' and intervenors' initial brief on implementation issues.

John W. Glendening, Jr., Barbara K. Heffernan and *Bruce B. Glendening*, for The Berkshire Gas Company, *et al.*; *William I. Harkaway, Harvey L. Reiter* and *Barbara M. Gunther*, for Consolidated Edison Company of New York, Inc.; *Patricia A. Curran*, for Cabot Corporation; *Donald K. Dankner* and *Frederick J. Killion*, for Central Hudson Gas and Electric Corporation; *Gary E. Guy*, for Equitable Gas Company; *Arnold H. Quint, James F. Bowe, Jr., O. Julia Weller* and *George L. Weber*, for National Fuel Gas Supply Corporation; *David I. Bloom* and *Sharon A. Cummings*, for Northern Illinois Gas Company; *Harry H. Voigt, M. Reamy Ancarrow, Mindy A. Buren, Diane B. Schratwieser* and *Edward B. Myers*, for Orange and Rockland Utilities, Inc.; *Glenn W. Letham* and *Kenneth M. Albert*, for Pennsylvania Gas and Water Company; *Thomas M. Patrick* and *Mark J. McGuire*, for The Peoples Gas Light and Coke Company; *Richard A. Solomon* and *David D'Alessandro*, for Public Service Commission of the State of New York were on the joint reply brief for certain petitioners and intervenors on "R" gas and released gas issue.

Robert F. Shapiro and *Thomas E. Hirsch, III*, entered appearances for The American Paper Institute, Inc.

Jerry W. Amos entered an appearance for Nashville Gas Company, a division of Piedmont Natural Gas Company, Inc.

Robert S. Waters, *Richard M. Merriman* and *Michael C. Tierney*, entered appearances for Dayton Power and Light Company.

Charles J. McClees, Jr., and *Craig H. Walker*, entered appearances for Shell Offshore, Inc.

David L. Konick entered an appearance for Brooklyn Union Gas Company.

Jack M. Irion entered an appearance for East Tennessee Group.

Stephen R. Melton and *William J. Grealis* entered appearances for United Gas Pipe Line Company.

James J. Hoecker entered an appearance for Arkla, Inc.

Before WILLIAMS, D.H. GINSBURG and SENTELLE, *Circuit Judges.*

Opinion for the Court filed by *Circuit Judge* SENTELLE.

SENTELLE, *Circuit Judge*: The Federal Energy Regulatory Commission ("FERC" or "the Commission") orders at issue require us to turn once again to certain aspects of the Commission's Order No. 500, 52 Fed. Reg. 30,334 (1987); *record remanded sub nom. American Gas Ass'n v. FERC*, Nos. 87-1588 *et al.*, slip op. (D.C. Cir. Oct. 16, 1989) ("*AGA*"). The orders before us implement the take-or-pay cost passthrough mechanism of Order No. 500. A host of natural gas pipeline companies, pipeline customers, local distribution companies ("LDCs"), industry associations, and state public service commissions petition for review.

Certain pipelines, customers, and LDCs argue that the Commission's "purchase deficiency" allocation mechanism

is unlawful because it violates the filed rate doctrine. We agree and therefore set aside the orders. As a result, disposition of most of petitioners' other claims is not essential to relieving them of burdens they claim are illegal. Nevertheless, because the Commission will undoubtedly attempt to revamp its passthrough policy in light of this decision, we will address a number of subsidiary issues which appear virtually certain to arise under any passthrough scheme.

I. Background

We recently summarized the genesis of the orders presented to us for review:

> The Federal Energy Regulatory Commission embarked in the early 1980s on an ambitious program to restructure the natural gas industry along lines more competitive than it had traditionally followed. One of the major components of this program, the encouragement of natural gas pipelines to adopt an "open access" transportation policy, failed to pass muster when we reviewed it, because the Commission failed to show either that it had authority to impose, or that it could rationalize the imposition of, a few of its components. *Associated Gas Distributors v. FERC*, 824 F.2d 981 (1987) (*AGD*). Because these components were inseparable from the whole, we vacated and remanded the Commission's Order No. 436 for the agency to cure the defects we had identified. The Commission promptly, in Order No. 500, issued an "interim rule," and undertook to issue a final rule when it had collected and analyzed certain information that it deemed essential.

AGA, slip op. at 10-11.

Unhappily, we found in *AGA* that Order No. 500 failed to comply with the mandate in *AGD*. We retained jurisdiction but remanded the record to the Commission for

issuance of a final rule within sixty days. The statutory, regulatory and economic context in which the Commission undertook to implement its open-access transportation policy is set out in detail in this Court's opinions in *AGD* and *AGA*. The passthrough mechanism is described in *AGA*, slip op. at 15-16. We refer to this background only as the need arises.

The Commission orders at issue implement the take-or-pay cost passthrough provisions of Order No. 500, with its "equitable sharing mechanism." This passthrough policy is part of a larger attempt by FERC to spread the costs of the take-or-pay problem over the whole industry, at least insofar as the open-access transportation policy has aggravated the problem. The mechanism at issue here attempts to shift some of the costs to the customers; the crediting system in *AGA*, on the other hand, attempted to shift costs to the producers. Under the passthrough mechanism, the cost buyouts and buydowns is shared between the pipeline and its customers. If a pipeline agreed to absorb between 25% and 50% of its take-or-pay costs, the pipeline would be permitted to recover an equivalent amount through a fixed charge. Such a pipeline would also be allowed an opportunity to recover the remaining costs through a volumetric surcharge on sales and transportation. Moreover, where the pipeline absorbed between 25% and 50% of the costs, the Commission established a rebuttable presumption that the remaining costs that the pipeline sought to pass on to its customers were prudently incurred. A pipeline customer could still challenge the pipeline's prudence, but it took a chance in doing so—it would have to pay its pro rata share of 100% of the costs ultimately found to have been prudently incurred.

To allocate the buyout and buydown costs among customers, FERC proposed the imposition of a demand surcharge on each pipeline customer. Customers' purchases of a natural gas decreased sharply during the period from

1983 to 1986 and thereby exacerbated the pipelines' problems. FERC therefore proposed to base the charge upon the customer's "deficiency" of purchases during this period. This "purchase deficiency" was to be calculated by measuring the customer's purchases in the "deficiency period" (1983-86) against its purchases in a prior "base period" (1981-82).

In October of 1987, after promulgation of Order No. 500, Tennessee Gas Pipeline Company ("Tennessee") filed a settlement proposal to resolve a previous Section 4 rate filing. The proposal called for direct charge recovery of 50% of Tennessee's reformation and buyout costs. Tennessee would absorb the remaining 50%. Tennessee also agreed to render a limited-term standby sales service. In addition, Tennessee proposed a 31 December 1989 "sunset date," which limited the time for filing recovery under the "equitable sharing mechanism," rather than Order No. 500's original sunset date of 31 December 1988 (which the Commission subsequently extended to 31 March 1989 in Order No. 500-F). Five competing settlement proposals were filed.

The Commission modified and approved Tennessee's proposed settlement. *Tennessee Gas Pipeline Co.*, 42 FERC ¶ 61,175 (1988). The Commission disallowed Tennessee from recovering through a fixed charge take-or-pay prepayments or any costs owed to affiliates. The Commission established a sunset date of 31 December 1988 for the filing of settlement costs for recovery. It purported to distinguish Tennessee's proposal from *Columbia Gas Transmission Corp. v. FERC*, 831 F.2d 1135 (D.C. Cir. 1987), *modified on reh'g*, 844 F.2d 879 (D.C. Cir. 1988), wherein this Court struck down as retroactive ratemaking Commission orders that allowed direct billing of certain costs based on past purchases, on the grounds that the Tennessee proposal involved merely the proper allocation of current settlement costs rather than a retroactive rate change.

On rehearing in May of 1988, FERC altered Tennessee's cost-allocation formula on the grounds that the formula in Order No. 500 relied solely on the "purchase deficiency" method, whereas the Tennessee formula combined the purchase deficiency method and a method based on the customer's annual quantity limitations. *Tennessee Gas Pipeline Co.*, 43 FERC ¶ 61,329 (1988). The Commission directed Tennessee to apply the purchase deficiency method to all buyout and buydown costs. The Commission also insisted on the 31 December 1988 sunset date (not 1989, as Tennessee requested).

Various petitioners filed for review in this Court on and after 27 May 1988.

In June of 1988, Tennessee filed tariff sheets that incorporated a 1989 sunset date. In July of 1988, the Commission accepted the tariff sheets and allowed Tennessee to begin direct billing its customers as of 1 July 1988 (subject to refund). *Tennessee Gas Pipeline Co.*, 44 FERC ¶ 61,039 (1988). The Commission still rejected the 1989 sunset date, and it did so again at the next Tennessee filing in September of 1988. *Tennessee Gas Pipeline Co.*, 44 FERC ¶ 61,401 (1988). In December of 1988, citing its Order No. 500-F, FERC extended the sunset date to 31 March 1989 and created the litigation exception (i.e., that take-or-pay liabilities in litigation as of 31 March 1989 were exempt from the deadline). Petitions for review of the Commission's orders were consolidated and are now before us.

II. Analysis

A. *Filed Rate Doctrine*

The Commission has allowed Tennessee to directly bill its customers surcharges proportional to the customers' purchase reductions during the 1983-86 "deficiency period," reductions calculated on the basis of the customers' purchases from Tennessee during the "base period"

of 1981-82. According to petitioners, the charges constitute a retroactive change in rates without advance notice and therefore violate the filed rate doctrine as expressed in *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 578 (1981) ("*Arkla*"), and *Columbia Gas.* Petitioners point out that *Columbia Gas* recognizes "predictability" as the fundamental policy underlying the filed rate doctrine and that the Commission's approval of the Tennessee settlement contravenes that policy: had Tennessee's customers known of these charges, they could have either purchased less gas from Tennessee during the base period or more gas during the deficiency period (or both) and could have thereby reduced their gas costs. In *Columbia Gas*, we struck down a direct billing mechanism where "the effect of the orders [was] quite clear: downstream purchasers [were] expected to pay a surcharge, over and above the rates on file at the time of sale, for gas they had already purchased." *Columbia Gas*, 831 F.2d at 1140.

The Commission claims that *Columbia Gas* is inapposite because the pricing mechanism at issue here does not really affect rates retroactively; rather, "what is involved here is simply a legitimate Commission decision to allocate *current* take-or-pay expenses in a fair and equitable fashion consistent with the Commission's board discretion. . . . All that the agency has done here is to utilize a calculation of a customer's past purchasing patterns in order to allocate its share of a *current* expense." Brief for Respondent FERC at 44 (emphases in original). The Commission argues that in *Columbia Gas* the direct bill charged customers for additional costs of producing gas that the customer had already purchased during a past period, where this case involves no "deferred costs" assessed for gas already purchased. Thus, according to the Commission, prior notice is not critical here because the charge does not recoup preexisting costs or prior losses. The Commission argues further that its actions with regard to minimum bills and gas curtailment pro-

grams have all involved use of a pipeline's purchasing pattern within an historical base period, and that this Court approved those actions. *See Wisconsin Gas*, 770 F.2d 1144 (D.C. Cir. 1985), *cert. denied sub nom. Transwestern Pipeline Co. v. FERC*, 476 U.S. 1114 (1986) (minimum bills), and *City of Willcox v. FPC*, 567 F.2d 394, 408-12 (D.C. Cir. 1977), *cert. denied*, 434 U.S. 1012 (1978) (curtailment plans during natural gas shortages of the 1970s); *cf. North Carolina v. FERC*, 584 F.2d 1003 (D.C. Cir. 1978) (remanding curtailment plan because of inaccurate base period). The filed rate doctrine is designed to prevent the utility's recovery of past losses, the Commission concludes, but it does not bar the imposition of current costs.

Petitioners respond that characterizing the costs as "current" is disingenuous because "[t]he level of the surcharge to each Tennessee customer is determined without reference to current or future purchases or service levels. Joint Reply Brief of Certain Petitioners and Intervenors in Support of Petitioners in Opposition to Orders Under Review at 5-6 ("Joint Reply Brief"). Petitioners do not argue that the Commission is prohibited from using accurate historical data in the course of determining future rates; rather, the Commission may not impose a direct surcharge geared to past gas purchases.

The Commission also argues that Tennessee's customers had sufficient notice of deficiency billing from the language of Order No. 380. *See* Order No. 380, FERC Stats. & Regs. ¶ 30,571 [Regulations Preambles 1982-1985] (1984), *aff'd in part, remanded in part sub nom. Wisconsin Gas Co. v. FERC*, 770 F.2d 1144 (D.C. Cir. 1985), *cert. denied sub nom. Transwestern Pipeline Co. v. FERC*, 476 U.S. 1114 (1986). Although petitioners acknowledge the theoretical possibility that advance notice could avoid the retroactivity problem, they claim that the Commission's approach is without foundation. First, they

point out that Order No. 380 was published in June of 1984; thus, they claim, the Order could not have provided any notice for the 1981-82 base period and could have provided only partial notice for the deficiency period. Second, Order No. 380 noted that carrying charges on prepayments "may require special consideration" but stated that "[n]o conclusion is reached on this point today . . . ." FERC Stats. & Regs. ¶ 30,571 at 30,971. Petitioners urge that this notice is impermissibly vague under case law, *United Gas Pipe Line Co. v. FERC*, 597 F.2d 581, 587 & n.27 (5th Cir. 1979), *cert. denied*, 445 U.S. 916 (1980), and under Commission precedent, *Mid-Louisiana Gas Co.*, 36 FERC ¶ 61,194 at 61,493 (1986), and that it is even less sufficient than the notice rejected in *Columbia Gas*. In addition, they point out that although the Order speaks of a "different allocation methodology," there was no suggestion that the methodology would be applied retroactively, and in any event the passage is not addressed to reformation and buyout costs. Indeed, although the matter is far from clear, the Commission itself seems to have recently eschewed the notion that Tennessee's customers received sufficient prior notice. *See National Fuel Gas Supply Corp.*, 45 FERC ¶ 61,269 at 61,839 (1988).

We agree with petitioners that the purchase allocation mechanism and its direct charge violate the filed rate doctrine. The Commission's attempted distinction of *Columbia Gas* is unpersuasive. Under *Columbia Gas*, the relevant question is not which costs are "current" and which are "past." Rather, the appropriate inquiry seeks to identify the purchase decisions to which the costs are attached. After making this inquiry, we have little doubt that the mechanism at issue violates the filed rate doctrine. Indeed, the Commission now even forces past customers who no longer purchase *any* gas from Tennessee to pay their share of the take-or-pay liability. *See United Gas Pipe Line Co.*, 47 FERC ¶ 61,163 (1989). On the other hand, current customers who did not buy gas from

Tennessee until after 1986 would not have to pay any part of the take-or-pay liability. As in *Columbia Gas*, "the effect of [these orders] is quite clear: downstream purchasers [such as petitioners here] are expected to pay a surcharge, over and above the rates on file at the time of sale, for gas they had already purchased." *Columbia Gas*, 831 F.2d at 1140.

The Commission's assertion that Order No. 380 provided sufficient notice is equally unavailing. Order No. 380 post-dated the entire base period and half of the deficiency period. The Commission can perhaps assume that petitioners have some acquaintance with regulatory changes in the natural gas industry, but it cannot require them to be clairvoyant. Upon consideration of the text of Order No. 380, we conclude that FERC's indication that carrying charges on prepayments "may require special consideration" is delphic at best; in any event, the reference is irrelevant in light of the Commission's explicit statement in Order No. 380 that it was making no final disposition of the issue.

The Commission asserts that a significant factual difference between *Columbia Gas* and the present case is that the direct charge in *Columbia Gas* was for gas *taken* whereas the direct charge at issue here is for gas *not taken*. This, of course, is only one way of looking at the basis of the charge in the present case. As a mathematical fact, the charge is as much a result of gas taken during the base period as it is of gas not taken during the deficiency period. In other words, the volume of gas that actually generates the specific charge, being the difference between base-period gas taken and deficiency-period gas not taken, is actual gas taken.

In any event, even if we were to recognize the difference asserted by the Commission, that recognition would not save the Commission because both the *Columbia Gas* orders and the mechanisms before us undermine the purpose of the filed rate doctrine. As we said in *Columbia*

Gas, "[p]roviding the necessary predictability is the whole purpose of the well established 'filed rate doctrine' . . . ." *Columbia Gas*, 831 F.2d at 1141 (quoting *Electrical Dist. No. 1 v. FERC*, 774 F.2d 490, 493 (D.C. Cir. 1985)). *Accord Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 577-78 (1981). We are not persuaded by the Commission's reference to curtailment plans. The rule at issue is the filed *rate* doctrine, and a curtailment plan is not a *rate* change. The fact that we do not apply the filed rate doctrine to curtailments is not a reason why we should not apply it to rates.

The Commission's attempt to analogize the pass-through mechanism to minimum bills is also misplaced. The two are similar insofar as they are both fixed charges imposed without reference to current purchases of gas, and can be avoided only by leaving the pipeline entirely through an abandonment proceeding or by a change of tariffs under Sections 4 or 5.[1] The passthrough mechanism differs from the minimum bills, however, in one crucial respect: the aggregate amount charged is calculated on the basis of past purchasing decisions, whereas minimum bills are generally based on current contract entitlement. *See* Order No. 380, FERC Stats. & Regs. [Regulations Preambles 1982-1985] ¶ 30,571 at 30,958-60 & n.5 (1984) (eliminating minimum commod-

[1] The Commission now apparently requires even customers who secure abandonment of service to pay their share under the pass-through mechanism. *See United Gas Pipe Line Co.*, 47 FERC ¶ 61,163 (1989). This practice reinforces our conclusion that the Commission views these as additional charges for past gas-purchasing decisions. However, *United Gas* itself recognized that it was a change in position, 47 FERC at 61,543, and thus we assume, in our comparison to minimum bills, that the Commission here would have allowed a customer of Tennessee to exit without paying its share of the take-or-pay burden. *See, e.g., North Penn Gas Co.*, 44 FERC ¶ 61,192 (1988). Of course, to the extent that customers cannot avoid the direct charge by abandoning service, the Commission's position becomes even harder to defend under the filed rate doctrine.

ity bill provisions which had been generally based on a "specified percentage of [the customer's] contract entitlement"). The Commission calls our attention to its own dicta concerning an earlier minimum bill based in part on historical data. *See Atlantic Seaboard Corp.* (Opinion No. 523), 38 FPC 91, 93-94 (1967), *aff'd*, 404 F.2d 1268 (D.C. Cir. 1968). The proposed bill effectively required a customer to pay for gas as if it took the same proportion of its current contract demand as it had taken in the base period of its base-period contract demand. As the charge was avoidable simply by keeping current takes above the minimum bill volume, the link between the current charge and the prior purchase decisions was far more attenuated than in the present case.

B. *Title I*

Title I of the Natural Gas Policy Act ("NGPA"), 15 U.S.C. §§ 3301-3333, establishes price ceilings ("maximum lawful prices" or "MLPs") for first sales of natural gas. Section 504(a) of Title V of the NGPA, 15 U.S.C. § 3414(a), makes it unlawful for any person to sell natural gas at a first sale price in excess of any applicable MLP. All parties before us assume, and we do not doubt, that the wellhead sales in question were first sales. Under Section 601(b) of Title VI, 15 U.S.C. § 3431(b), payments made for natural gas that are not in violation of Title I are deemed just and reasonable, and they may be passed through, absent a showing of fraud or abuse; conversely, the Commission treats amounts not found to be just and reasonable under Section 601(b) as per se imprudent and therefore ineligible for passthrough.

Petitioners argue that this statutory structure means that "all forms of consideration received by the producer-seller must be added together to determine whether the total *value* received exceeds the MLP." Joint Initial Brief of Certain Petitioners and Intervenors in Support of Petitioners in Opposition to Orders Under Review at 57 (empshasis in original). Petitioners complain that the Commission has allowed two loopholes to the MLP. First,

in its 1985 policy statement, *Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations*, FERC Stats. & Regs. ¶ 30,637 (1985), the Commission indicated that take-or-pay buyout and buydown costs would not be considered part of a pipeline's payments for gas, and therefore would not violate Title I. Second, in July of 1988, the Commission allegedly opened the second loophole by deciding in *ANR Pipeline Co. v. Wagner & Brown*, 44 FERC ¶ 61,057 at 61,155 (1988), *reh'g denied*, FERC Docket No. GP86-54-001, slip op. (October 30, 1989), that nonrecoupable prepayments are not part of the consideration paid for gas and therefore do not violate Title I. Nonrecoupable prepayments are payments made by the pipeline to the producer for gas that the pipeline is not able to "make up" by taking amounts in excess of its take-or-pay option in a later year. The pipeline is usually given a certain period (a "make-up period") in which to take the gas. The make-up period is an important feature of take-or-pay contracts because, to the extent the pipeline takes the gas during the make-up period, it reduces the real burden of such contracts to the time value of the prepayment. After the expiration of the make-up period, the producer is free to resell the gas. According to petitioners, the Commission's argument that prepayments are irrelevant to Title I is disproved by pre-NGPA case law holding that advance payments to producers for gas were part of the price paid for the gas. *Tennessee Gas Pipeline Co. v. FERC*, 606 F.2d 1094, 1102-03 (D.C. Cir. 1979), *cert. denied*, 445 U.S. 920 (1980), and *cert. denied sub nom. Transcontinental Gas Pipe Line Corp. v. FERC*, 447 U.S. 922 (1980), and that a take-or-pay prepayment was a sale even absent delivery. *Callery Properties, Inc. v. FPC*, 335 F.2d 1004, 1021 (5th Cir. 1964).

Petitioners seek to close the first of these asserted loopholes by having the Commission add together (1) buyout and buydown payments made for gas not taken

under a contract and (2) all payments made for gas taken. The sum would be divided by the amount of gas actually taken, and petitioners would find a violation of the NGPA to the extent that the resulting "average price" exceeded the MLP. Petitioners argue further that the Commission's reliance on a policy statement in approving a passthrough of Tennessee's buyout and buydown costs violates *Pacific Gas & Electric Co. v. FPC*, 506 F.2d 33 (D.C. Cir. 1974) (policy statement requires independent justification when applied to particular circumstances), and that the policy statement is conclusory and runs against the Commission's earlier recognition of the complexity of this issue. Petitioners also claim that the Commission's conclusion that these payments are not part of the price of gas disregards this Court's decision in *Southern Union Co. v. FERC*, 857 F.2d 812 (D.C. Cir. 1988) (gas contract damages are damages for the price of the gas). Therefore, any such costs paid on a gas contract for regulated gas sold at the MLP must violate Title I. Moreover, petitioners claim that if buyouts and buydowns need not be generally counted for purposes of determining MLP compliance, one particular set of buyouts and buydowns must—those made in lieu of nonrecoupable prepayments which themselves would necessarily violate Title I. Invalidating this subset is allegedly necessary in order to avoid a "massive circumvention of Title I." Joint Initial Brief at 63.

The Commission responds that the principles of its *Wagner & Brown* decision excluding nonrecoupable prepayments from the definition of "payments for gas" and therefore from Title I were confirmed in *Diamond Shamrock Exploration Co. v. Hodel*, 853 F.2d 1159 (5th Cir. 1988). In that case, the Fifth Circuit held that take-or-pay payments for gas not actually taken are not subject to royalty payments under the Outer Continental Shelf Lands Act, 43 U.S.C. §§ 1331-1336, because they are not "payments for the sale of gas." The Commission argues

further that under pre-NGPA law nonrecoupable take-or-pay payments "were never held to violate NGA [Natural Gas Act] area rate or national rate ceilings, even if they became non-recoupable . . . ." Brief for Respondent FERC at 32. The Commission also points out that the Tenth Circuit recently cited both *Diamond Shamrock* and *Wagner & Brown* when it held that take-or-pay payments are not payments for the sale of gas. *Kaiser-Francis Oil Co. v. Producers' Gas Co.*, 870 F.2d 563, 570 (10th Cir. 1989). FERC claims that there is no case that requires the Commission to find a Title I violation in circumstances such as petitioners describe, where the pipeline never takes the gas and the producer later resells it.

Buyout and buydown costs fall within the same rule, according to the Commission, because "they also involve the situation in which payments are made to avoid obligations to buy gas, not to pay for gas." Brief for Respondent FERC at 34. This Court's *Southern Union* decision on gas contract damages can be readily distinguished, FERC claims, because that case involved a dispute over the price of gas actually sold, whereas the costs here are to reduce exposure for gas not taken or to reform the terms of future sales.

Petitioners attempt to distinguish *Diamond Shamrock* on the grounds that *Diamond Shamrock* addressed the issue of whether prepayments are subject to royalty payments, at least where the government is the claimant of the royalties. In petitioners' view, the *Shamrock* court's holding—that royalties are due only on gas actually produced and taken, not on prepayments—is irrelevant to the Title I question before us. Petitioners also claim that *Kaiser-Francis* relied on the flawed *Wagner & Brown* theory without making an independent judgment on the Title I question and should be rejected. Finally, petitioners argue that FERC misperceives their Title I attack: rather than being a situation where no gas has changed hands at all, as FERC would describe it, the problem

arises precisely because the purchaser has taken some volumes of gas but has also made additional payments for the gas it could not take. Thus, the "sale" and the "prepayment" are part of the same contractual event. Petitioners assert that the prepayment (or the cost of buyouts and buydowns) "plainly relates to the volumes delivered to Tennessee by that seller pursuant to that contract, and to none other." Joint Reply Brief at 32. Those volumes are therefore necessary, petitioners conclude, "in order to determine whether the total payment per unit of volume received exceeds the maximum lawful price (MLP)." *Id.* at 33.

We conclude that the Commission's position on this issue, as evidenced by the *Wagner & Brown* proceedings, is final; we do not believe that the Commission has deferred the question to a later date or has merely issued a policy statement. We also uphold the Commission on the merits of this issue. The amount paid under a contract (for gas taken and for gas not taken, which includes non-recoupable prepayments as well as buyouts and buydowns), divided by the units of gas actually taken, may indeed yield a figure that is in excess of NGPA ceiling prices. Such a circumstance alone, however, does not violate Title I. For purposes of Section 504(a) of Title V of the NGPA, 15 U.S.C. § 3414(a), we agree with the Tenth Circuit's conclusion in *Kaiser-Francis* that prepayments are not payments for gas to the extent that the gas is not taken. We will not impute to Congress an intent to preclude all sales at or below the lawful ceiling price that are coupled with other contractual obligations so as to yield an average price in excess of the MLP. Such a construction of Title I is what petitioners' analysis requires. In the hypothetical situation of a gas buyer's partial breach and the seller's subsequent action for damages, we would not deny the seller a remedy because his damages award plus the amount paid for the gas taken, divided by the units of gas actually taken,

yielded a quotient greater than the relevant NGPA ceiling price. Although take-or-pay contracts are not identical to the hypothetical contract damages situation, they serve the same purposes as other fixed contractual obligations, and petitioners' theory would invalidate all take-or-pay contracts that involve sales at the ceiling price to the extent they become non-recoupable.

We find nothing in petitioners' argument that warrants such a conclusion. The Fifth Circuit's decision in *Callery Properties*, 335 F.2d at 1021 (upholding the Commission's jurisdiction under Section 1(b) of the NGA, 15 U.S.C. § 717(b), because a take-or-pay provision can be a "sale" within the meaning of that section even when no gas is delivered), is inapposite to the issue now before us. The construction of Section 1(b) of the NGA has no bearing on our interpretation of the phrase "any amount paid" under Section 601(b) of the NGPA. Our dicision in *Tennessee Gas*, 606 F.2d at 1102-03, can be distinguished because that case involved advance payments for gas that was actually taken: the prepayments were, essentially, "recouped." Similarly, *Southern Union* is not controlling in this case because it involved an award of damages intended to increase the price of natural gas that had actually been taken by the purchaser. In the case before us, the issue arises precisely because prepayments are made for gas that is *not taken*. Our holding today is therefore entirely consistent with *Tennessee Gas* and *Southern Union*.

C. *Tennessee's Settlements with Equitable and Columbia*

Equitable Gas Company ("Equitable) and Columbia Gas Transmission Corporation ("Columbia") are customers of Tennessee. Their petitions involve their Commission-approved take-or-pay settlement agreements with Tennessee. Columbia seeks "credit" for payments that it has already made to Tennessee, pursuant to its agreement, in order to reimburse Tennessee for take-or-

pay costs. Equitable argues that its agreement with Tennessee was still in force until 31 October 1989 and that Tennessee cannot recover any amount from Equitable in excess of the amount specified in the settlement during the term of that settlement. Because the Commission did not give an adequate, reasoned basis for its treatment of these agreements under the purchase deficiency allocation, we vacate the orders on this point and remand to the Commission. On remand, the Commission is to justify in a rational and adequate fashion the effect of the purchase deficiency allocation on these agreements. Otherwise, the Commission must adjust any recovery from either Equitable or Columbia for any take-or-pay liability that is covered by the settlement agreements.

Tennessee and Equitable entered into a settlement agreement on 11 April 1986 (the "April settlement"). The Commission approved the April settlement. *Tennessee Gas Pipeline Co.*, 40 FERC ¶ 61,145 (1987). The April settlement provided that Equitable and certain other customers would be directly billed an annual amount for take-or-pay costs beginning 1 February 1986 and ending 31 October 1989. For the duration of the April settlement, Tennessee could not charge Equitable for any take-or-pay costs greater than those allowed by the settlement's terms. By its own terms, the April settlement specifically prohibited termination by means of rate adjustment provisions and settlement agreements. Equitable argues that Tennessee's settlement proposal of 14 October 1987 violated the April settlement by proposing to increase take-or-pay charges to Equitable prior to the expiration of the settlement. Equitable challenges the Commission's authority to approve a modified Tennessee proposal in derogation of the April settlement.

Similarly, Columbia paid its proportional share of take-or-pay costs for the years 1982 and 1983 pursuant to a settlement agreement with Tennessee originally entered into in November of 1984 (the "November settlement").

The Commission approved the November settlement. *Columbia Gas Transmission Corp. v. Tennessee Gas Pipeline Co.*, 29 FERC ¶ 61,203 (1984), *reh'g*, 31 FERC ¶ 61,053 (1985). This settlement was subsequently extended to include Tennessee's take-or-pay costs through July of 1984. *Columbia Gas Transmission Corp.*, 31 FERC ¶ 61,307 (1985). On rehearing of Tennessee's allocation proposal, the Commission ordered Tennessee to use the purchase deficiency methodology exclusively, as opposed to a combination of purchase deficiency and contract demand levels. *Tennessee Gas Pipeline Co.*, 43 FERC ¶ 61,329 at 61,931 (1988). Tennessee altered its methodology such that credit for payments made pursuant to the November settlement was eliminated. The Commission subsequently approved this compliance filing, subject to certain conditions not relevant here. *Tennessee Gas Pipeline Co.*, 44 FERC ¶ 61,039 (1988). Columbia challenged as abritrary and unsupported the Commission's refusal to require credit for past take-or-pay payments pursuant to the November settlement. The Commission dismissed Columbia's challenge on rehearing. *Tennessee Gas Pipeline Co.*, 44 FERC ¶ 61,155 (1988).

Equitable argues that Tennessee's unilateral imposition of the higher take-or-pay charges without a general rate filing under Section 4 of the NGA, 15 U.S.C. § 717c, violated both the *Mobile-Sierra* doctrine, *see FPC v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), and *United Gas Pipe Line Co. v. Mobile Gas Corp.*, 350 U.S. 332 (1956), and the express provisions of the April settlement. As to the Commission's finding on rehearing, *Tennessee Gas Pipeline Co.*, 43 FERC ¶ 61,329 at 61,935 (1988), that allowing the April settlement to stand would be "unduly discriminatory" in violation of Section 5 of the NGA, 15 U.S.C. § 717d, Equitable points out that the Commission failed to find that any of the parties that paid take-or-pay costs under the April settlement were victims of undue discrimination; failed to find that Ten-

nessee's customers not party to the April settlement would be affected if the settlement were not abrogated; and failed to find that imposing take-or-pay obligations on Equitable greater than those established by the settlement would either remedy the undue discrimination or work beneficent effects upon Tennessee's customers or downstream consumers.

Columbia's claim is also based on allegations that the Commission acted arbitrarily. Columbia argues that, by its own terms, the Commission's use of the purchase deficiency mechanism was designed to rationally correlate take-or-pay cost incurrence with cost causation. *Tennessee Gas Pipeline Co.*, 43 FERC ¶ 61,329 at 61,930 (1988). According to Columbia, this approach should have led the Commission to require credit for take-or-pay payments made to Tennessee. Indeed, Columbia argues, it has already paid Tennessee for any take-or-pay costs Columbia may have generated by purchase cutbacks during the period from 1982 to 1984 that is covered by the November settlement. Columbia protests that the Commission has presented no reasoned explanation for denying credit and thus departing from the cost causation methodology expounded in its own orders. Columbia argues that the Commission's analogy of settlement payments to "released gas sales" (i.e., sales of gas directly to a customer by a producer after a pipeline has released the gas to the producer in exchange for take-or-pay credit), credit for which is denied as an " 'unwarranted double benefit,' " *Tennessee Gas Pipeline Co.*, 46 FERC ¶ 61,264 at 61,776, is inapposite because customers in the released gas situation have already reaped the benefit of the lower price that flows from such releases, whereas the only benefit to Columbia from its settlement payments is a coordinate diminution of its take-or-pay exposure.

The Commission responds that Equitable's argument is overly formalistic: when the Commission rejected Tennes-

see's initial Section 4 filing and issued its own decision, the Commission argues, it implemented a rate change that was the result of a "proceeding instituted by the Commission pursuant to Section 5" as contemplated by the April agreement. According to FERC, its actions were therefore consistent with the settlement, and the fact that the rate change was not initiated by the *pipeline company* is irrelevant. The Commission argues further that Equitable's argument is inconsistent with Equitable's own prior conduct because Equitable allegedly recognized that the April settlement would be supplanted upon issuance of a decision on the merits in the present case. In any event, the Commission concludes, no different result is required here even if Equitable's arguments are correct because the practical relief available to Equitable is minimal inasmuch as Equitable's "overall allocation cannot be reduced merely because the payment level could not be applied to it until October 1989 [the date at which the April settlement expired]." Brief for Respondent FERC at 42.

As to Columbia, the Commission argues that if it were to approve the "credit" requested by Columbia, it would have to make a similar adjustment every time a pipeline and one of its customers entered into an agreement that could be read as relieving the pipeline of take-or-pay liability (as an example, FERC points to the so-called "released gas programs"). The Commission also claims that it has consistently denied such credits or adjustments on the grounds that a customer in Columbia's position receives a number of additional benefits in such agreements, and that therefore Columbia's request is merely an attempt to add extra terms to the original agreement.

Although the Commission correctly asserts that it is entitled to deference in the interpretation of settlement agreements before it, *National Fuel Gas Supply Corp. v. FERC*, 811 F.2d 1563, 1569 (D.C. Cir.), *cert. denied*, 484 U.S. 869 (1987), the Commission is obligated to provide us with a reasoned and consistent explanation to which

we can defer. *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29, 43 (1983) ("[T]he agency must examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.' ") (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)); *Panhandle Eastern Pipe Line Co. v. FERC*, No. 87-1431, slip op. at 36 (D.C. Cir. August 1, 1989) ("The agency's determination must reflect reasoned decisionmaking that has adequate support in the record and must include an 'understandable' agency analysis and rationale.") (citing *Tarpon Transmission Co. v. FERC*, 860 F.2d 439, 442 (D.C. Cir. 1988)). The Commission's findings and rationales with regard to the treatment of these settlements are largely non-existent. To the extent that they are discernible, they are generally unclear or contradictory. To the extent that they are unambiguous, they are unsupported. Such a state of affairs prohibits us from deferring to the Commission on this issue.[2]

In particular, we find unpersuasive the Commission's argument that its orders here do not violate the *Mobile-Sierra* doctrine with regard to Equitable and that its orders somehow come within the Section 5 language of the April settlement: as Equitable points out, the Commission seems to have made no finding that would justify a Section 5 rate change. Moreover, although Equitable does not make clear the exact sweep of its argument that its "liability during the 'RP85-178 Period' [ending October 31, 1989] is limited to the amount specified in the April 11 Settlement," Reply Brief of Petitioner Equitable Gas Co. at 6, we take it to express a view that even new

[2] Because we do not reach the issue of the lawfulness of the Commission's treatment of released gas sales, we point out that our decision does not turn on the asserted distinction between settlement payments and released gas, and we express no opinion on that question.

passthrough mechanisms created by FERC on remand might conflict with its settlement. If FERC implements another passthrough mechanism, it should either allow Equitable's settlement with Tennessee to supercede any new passthrough mechanism for the period in which it was operative, or it should provide a more well-reasoned explanation for its decision not to do so.

As to Columbia, regardless of the fact that its settlement with Tennessee used a cost-causation approach similar to that used by the Commission here, it has already paid an amount agreed upon between itself and Tennessee for its share of take-or-pay liability for a specific period. It should be given credit for having done so, absent a good explanation.

D. *Section 5, the Sunset Provision, the Litigation Exception, and Implementation Issues*

Petitioners argue that the Commission erred in failing to consider whether the buyout and buydown costs at issue were unjust and unreasonable and therefore violated Section 5 of the NGA, 15 U.S.C. § 717d. The Commission responds that this question should be considered in the generic Order No. 500 proceedings.

This issue is now mooted by our recent decision in *American Gas Ass'n v. FERC*, Nos. 87-1588 et al., slip op. (D.C. Cir. October 16, 1989) ("*AGA*"). As we said in *AGA*, the Commission's "half-explained cunctation" with regard to the Section 5 issue convinced us that it was engaged in dilatory tactics so as to avoid either exercising its Section 5 powers or explaining its inaction. *AGA*, slip op. at 23 (citing *Mid-Tex Electric Cooperative v. FERC*, 822 F.2d 1123, 1132 (D.C. Cir. 1987)). We therefore remanded the record to the Commission for promulgation of a final rule within sixty days. We trust that this Section 5 issue will be clarified and hopefully resolved upon the timely issuance of a final rule as a replacement for interim Order No. 500.

Various petitioners attack the deadline of 31 March 1989 for filing under the "equitable sharing mechanism" (the "sunset date") and the Commission's "litigation exception" to the sunset date (i.e., that take-or-pay liabilities in litigation as of 31 March 1989 are exempt from the deadline). Our decision in *AGA* invalidated the sunset provision as arbitrary and capricious. *AGA*, slip op. at 29-30. Because the litigation exception was merely a dispensation from the sunset date, that issue is now moot.

Finally, because of our conclusion that direct billing based on purchase deficiencies violates the filed rate doctrine, all implementation issues are moot.

III. Conclusion

The purchase deficiency allocation mechanism violates the filed rate doctrine. Because we find that prepayments are not payments for gas to the extent that the gas is not taken, we reject petitioners' Title I attack on the orders before us. The Commission did not present a reasoned explanation with regard to the effect of its purchase deficiency allocation on Equitable and Columbia. On remand, the Commission must adequately and reasonably justify its orders, particularly with regard to the *Mobile-Sierra* doctrine, to findings necessary prior to Commission action, and to its refusal to grant Columbia "credit" for payments already made. Otherwise, the Commission must adjust any recovery from either customer for any take-or-pay liability covered by their respective agreements. Our recent decision in *AGA* moots various petitioners' claims as to Section 5, the sunset provision, and the litigation exception. We vacate the orders at issue and remand to the Commission for proceedings not inconsistent with this opinion.

APPENDIX B

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Issued March 30, 1990

No. 88-1385

ASSOCIATED GAS DISTRIBUTORS,
Petitioner

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

---

and Consolidated Cases

On Petitioners' Suggestion for Rehearing *en banc*

Before: WALD, *Chief Judge*; MIKVA, EDWARDS, RUTH B. GINSBURG, SILBERMAN, BUCKLEY, WILLIAMS, D.H. GINSBURG, SENTELLE and THOMAS, *Circuit Judges*.

ORDER

The Suggestions for Rehearing En Banc of the various parties have been circulated to the full court. The taking of a vote was requested only on the issue of whether the equitable sharing mechanism mandated by respondent in Order No. 500 violates the filed rate doctrine. Thereafter, a majority of the judges of the court in regular,

active service did not vote in favor of rehearing *en banc*. Upon consideration of the foregoing it is

ORDERED by the Court *en banc* that all of the suggestions are denied.

Per Curiam
FOR THE COURT
CONSTANCE L. DUPRE
Clerk

Circuit Judges D.H. GINSBURG and THOMAS did not participate in this order.

A statement of *Circuit Judge* WILLIAMS concurring in the denial of rehearing *en banc* is attached.

A statement of *Chief Judge* WALD dissenting from the denial of rehearing *en banc*, joined by *Circuit Judges* MIKVA and EDWARDS, is also attached.

WILLIAMS, *Circuit Judge*, concurring in denial of rehearing and rehearing *en banc*: I write here only to correct what seems to be a misconception about the scope of our holding regarding the filed rate doctrine.

We have not always clearly distinguished between the filed rate doctrine and the retroactive ratemaking doctrine, doubtless because they often overlap. Although labeling at this advanced state of the doctrines' lives may be arbitrary, the following strikes me as sensible. Under the filed rate doctrine, a regulated entity may not charge, or be forced by the Commission to charge, a rate different from the one on file with the Commission for a particular good or service. Subject only to refunds provided for under § 4 of the Natural Gas Act, 15 U.S.C. § 717c (1988), this rule holds whether the attempted surcharge or rebate occurs at the time of service, *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 581 (1981), or at some later time, *Columbia Gas Transmission Corp. v. FERC*, 831 F.2d 1135 (D.C. Cir. 1987); *Public Utilities Commission of California v. FERC*, Nos. 88-1530, 88-1572

(D.C. Cir. Feb. 2, 1990), slip op. at 19-21; *Associated Gas Distributors v. FERC*, 893 F.2d 349, 354-57 (D.C. Cir. 1989); cf. *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 618 (1944) (no reparation order for past rates found unjustly or unreasonably high). As a necessary corollary to that rule, we must ask to what a new proposed charge *relates*. Otherwise we cannot know whether it is in addition to the rate already charged for some past service or is instead a charge for current service. In this context, whether the *cost* sought to be recovered is past or current is not directly relevant, contrary to the contentions of some petitions for rehearing. If current gas costs surged, for example, and the Commission responded by authorizing a surcharge on individual customers' 1984 takes, the violation of the filed rate doctrine would be plain.

The retroactive ratemaking doctrine, on the other hand, focuses on how the current rate is determined. Under this doctrine, the Commission is prohibited from adjusting current rates to make up for previous over- or under-collections of costs in prior periods. The retroactive ratemaking doctrine is thus a logical outgrowth of the filed rate doctrine, prohibiting the Commission from doing indirectly what it cannot do directly. The Commission may not allow a utility to "recoup past losses," *City of Piqua v. FERC*, 610 F.2d 960, 964 (D.C. Cir. 1979), nor may it force a utility to reduce its current rates to make up for overcollections in previous periods. See *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 595-96, 618 (1944) (because it is unlawful for Commission to issue reparation order for past excessive rates, utility cannot be "person aggrieved" within meaning of § 19(b) of Natural Gas Act as a result of Commission's incidental findings of such excesses); cf. *Public Utilities Commission of California*, slip op. at 19. To allow such adjustments would cause current rates to be either unreasonably high or low. The Commission may not disinter the past merely because experience has belied projections, whether the

advantage went to customers or the utility; bygones are bygones. After-the-fact adjustments would also upset the balance effected by §§ 4 and 5. While § 4's refund provision protects the customers from a rate that is unreasonably high when filed (examined as of the filing), § 5's requirement that relief be prospective only assures the utility that rates passing scrutiny under § 4 will not be undone. Finally, as the utility keeps cost savings and bears excess costs, it has an incentive to efficient operation. It is for purposes of this doctrine that a court must ask whether the costs are past.

Some petitions for rehearing suggest that the panel decision represents a peculiarly aggressive application of the filed rate doctrine. It is hard, however, to see how that rule would retain any force if the proposed purchase deficiency charge were allowed. It is virtually indistinguishable from the Commission's substituting in 1988 a new rate schedule for gas purchased in 1983-86. It applies to customers who leave the system, including one that filed for abandonment *before* its supplier pipeline filed its "equitable sharing" rate. See panel decision, 893 F.2d at 356 n.1, and *United Gas Pipe Line Co.*, 47 FERC ¶ 61,163 (1989). Under *United*, the period of entitlement subjecting a customer to the charge, i.e., between the pipeline's filing the rate and completion of the customer's abandonment proceedings, could be as little as one day or one hour. Thus the charge is not only pegged precisely to customer takes (or failures to take) in the long past deficiency period, but its relation either to current entitlements or takes is only nominal. The conclusion seems inescapable that as conceived by the Commission it is a charge for gas service in the 1983-86 period and as such violates the filed rate doctrine.

WALD, *Chief Judge*, with whom MIKVA and EDWARDS, *Circuit Judges*, join: We would vote to hear *en banc* the issue of whether the equitable sharing mechanism mandated by the FERC in Order No. 500 violates the filed rate doctrine.

It is not at all clear that as it applies to consumers "let off the hook" by Order No. 436, the equitable sharing mechanism invoked by the Commission in Order No. 500 violates the filed rate doctrine. Prior to Order No. 436, pipeline companies had entered into take-or-pay contracts with producers to track the contracts they had or expected to enter into with consumers. These contracts with the consumers presumably specified that the consumers would be paying Y price for X amount of gas. Order No. 436, however, allowed the consumers to break the contracts prior to purchasing the amount of gas specified in the contracts. Thus, the consumers were in effect getting Z amount of gas (where Z is less than X) for the same "bulk rate" price. In other words, they got a windfall. The FERC, then, did not "revise" these rates; circumstances subsequent to the signing of the contracts between the consumers and the pipelines altered the deal—and, in effect, the rate—originally agreed to by the consumers. The FERC's decision to reallocate some of these current costs did not violate the filed rate doctrine because the deal originally agreed to by the consumers had already been abrogated by the FERC. Neither the purchase decisions to which the consumers' original costs were attached nor the rates pursuant to them were still valid. It was a brand new world: there were no "old rates" to change.

In a time when the structure of the natural gas industry is undergoing a sea change, the FERC must be granted considerable discretion to ensure that the transition period is handled in a manner than minimizes the disruption in the industry. This court itself, in remanding Order No. 436, instructed the FERC to do something

about the pervasive take-or-pay contracts that hindered pipelines from making the move from an entrepreneurial to a common carrier status. The FERC's resultant Order No. 500 seems to us to be a good faith, and not unreasonable, response to the mandate.

The panel's overly rigid interpretation of the filed rate doctrine to invalidate that Order leaves the FERC essentially powerless to take care of the take-or-pay crisis. The panel suggests that if pipelines wish to share their multi-billion dollar loss with consumers, they must do so by adding a surcharge to future sales. In a competitive market, of course, the "take-or-pay" pipelines will not be able to do this since such surcharges would raise their prices to an uncompetitive level. But even if some costs could be passed on to future consumers, that would still mean that total losses would be allocated *in*-equitably. Those consumers who are in a position to take advantage of open-access shipping will bear proportionately less of the loss than those who cannot—even though the former (by switching to other pipelines) are the ones responsible for the loss.

The significant effect of the invalidation of Order No. 500 on the functioning of the industry and on the FERC's ability to regulate this "quiet revolution" in the gas industry certainly seems important enough to warrant our *en banc* consideration.

APPENDIX C

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 88-1385

ASSOCIATED GAS DISTRIBUTORS,
Petitioner

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

---

and Consolidated Cases

Before: WILLIAMS, D. H. GINSBURG and SENTELLE,
Circuit Judges

ORDER

[Filed Apr. 23, 1990]

Upon consideration of the motions for stay of mandate pending applications for writs of certiorari filed by respondent, intervenor local distribution companies and jointly by Tennessee Gas Pipeline Company and National Fuel Gas Supply Corporation, the responses thereto and of the replies, it is

Ordered, by the Court, that the Clerk is directed to withhold issuance of the mandate of the court for a period of sixty days from the date of this order with respect to all issues decided by the court except the settlement

termination issue raised by Equitable Gas Company in Case No. 88-1400. With regard to this latter issue, the Clerk is directed to issue the mandate promptly.

Per Curiam
FOR THE COURT:

CONSTANCE L. DUPRE
Clerk

/s/ Robert A. Bonner
ROBERT A. BONNER
Deputy Clerk

APPENDIX D

FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RP86-119-000

TENNESSEE GAS PIPELINE COMPANY,
a Division of Tenneco Inc.

Initial Decision

(Issued July 9, 1987)

Thomas I. Megan, Presiding Administrative Law Judge.

Appearances

Terence J. Collins, Margaret L. Bollinger, Dale A. Wright, Robert H. Benna, Michael E. Small and *Alan J. Statman* for Tennessee Gas Pipeline Company, a Division of Tenneco Inc.

Jonathan D. Schneider for New York State Electric and Gas Corporation

John L. Shailer, Thomas E. Morgan, Giles H. Snyder and *Ronald N. Carroll* for Columbia Gas Distribution Companies

James M. Bushee and *William H. Penniman* for Process Gas Consumers Group and American Iron and Steel Institute

Jack Lahey for New England Energy Group

Patrick J. Whittle and *Brian D. O'Neill* for Trunkline Gas Company

M. Reamy Ancarrow, Harry H. Voigt, Minday A. Buren and *Laurie A. Frost* for Niagara Mohawk Power Corporation and Orange and Rockland Utilities, Inc.

Lynne H. Church, Robert Fleishman, Jennifer N. Waters, Daniel Watkiss, J. Thomas Wolfe, Robert E. Litan, Simon Lazarus and *Lawrence Fullerton* for Baltimore Gas and Electric Company

J. Paul Douglas, Blaine Yamagata, Thomas D. Carmel and *Peter G. Hirst* for Conoco, Inc., Mobil Oil Exploration & Producing Southeast, Inc., Mobil Producing Texas & New Mexico, Inc., Shell Offshore, Inc., and Shell Western E&P, Inc.

Joseph Stiles for Exxon Company U.S.A.

Thomas G. Wagner for Mobil Oil Exploration & Producing Southeast, Inc., and Mobil Producing Texas & New Mexico, Inc.

Barry K. Cosey for Producer-Marketer-Transportation Group

Barry K. Cosey for Pennsylvania Natural Gas Associates.

Charles J. McClees, Jr. for Shell Offshore and Shell Western E&P, Inc.

Ronald N. Carroll, Giles D. H. Snyder, Stephen J. Small, John H. Pickering, Timothy N. Black, Neal T. Kilminster and *Gary D. Wilson* for Columbia Gas Transmission Corporation.

William A. Williams, John F. Harrington and *Kim R. Cocklin* for Texas Gas Transmission Corporation.

Norma J. Rosner for Chevron U.S.A., Inc.

David D'Alessandro, Richard A. Solomon and *David E. Blabey* for the Public Service Commission of the State of New York

David D'Alessandro and *Richard A. Solomon* for the Public Service Commission of the Commonwealth of Kentucky

Channing D. Strother, Jr. for Chattanooga Gas Company

Reuben Goldberg and *Joshua Menter* for North Penn Gas Company

Thomas E. Midyett for East Tennessee Natural Gas Company, Inc.

James J. Stoker, III, James F. Bowe, Jr. and *Lisa A. Clark* for Long Island Lighting Company

Mark J. McGuire, Thomas M. Patrick, Karen Cargill and *James Hinchliff* for Peoples Gas Light & Coke Company

David I. Bloom, Robert A. Helman, Wendell H. Adair, Jr., Patricia A. McCoy and *Sharon A. Cummings* for Northern Illinois Gas Company

John T. Miller for Elizabethtown Gas Company

Karol Lyn Newman, Jacolyn A. Simmons and *Kathleen D. Gardner* for Arkansas Louisiana Gas Company

Michael J. Manning and *James F. Moriarty* for Tenneseee SGS Group

Sarah K. Walls for Cabot Corporation

George L. Weber, Joseph O. Fryxell and *John T. Ketcham* for National Fuel Gas Supply Corporation.

Denis E. George, Mark R. Spivak, Daniel John Regan, Jr., and *Stephen Huntoon* for Dayton Power & Light Company

Gary E. Guy and *Michael W. Hall* for The Brooklyn Union Gas Company

Richard W. Miller, Jr., for ANR Pipeline Company

Earl L. Fisher, Jr. and *Michael Bridges* for The Inland Gas Company, Inc.

James W. Stetson for Massachusetts Public Utilities Commission

David E. Duren for Texas Eastern Transmission Corporation

Jack M. Irion for East Tennessee Group

John W. Glendening, Jr., Bruce Glendening, Joseph M. Oliver, Jr. and *Jennifer N. Waters* for New England Customer Group

Susan B. Russell, Charles R. Brown, Mark G. Magnuson, Stephen E. Williams, Georgia Carter and *Henry P. Sullivan* for Consolidated Gas Transmission Corporation

Jerry W. Amos for Piedmont Natural Gas Company, Inc.

Paul A. Tiburzi for Pennsylvania and Southern Gas Company

Virginia A. Chaffee and *Philip D. Endom* for United Gas Pipe Line Company

Paul E. Goldstein and *Paul W. Mallory* for Natural Gas Pipeline Company of America

Demetrius G. Pulas, Jr. and *James R. Choukas-Bradley* for the Cities of Clarksville, Springfield and Portland, Tennessee

Harvey L. Reiter and *William I. Harkaway* for Consolidated Edison Company of New York, Inc.

Paul W. Diehl and *Stanley M. Morley* for Alabama-Tennessee Natural Gas Company

Richard M. Blumberg for Meridian Oil, Inc., and Southland Royalty Company

Hugh J. Hahoney, James R. Lacey and *Shawn P. Leyden* for Public Service Electric and Gas Company

Charles F. Hoffman, John E. Povilaitis and *Terrance J. Fitzpatrick* for the Pennsylvania Public Utility Commission.

Christine G. Benagh, George M. Knapp and *Richard N. George* for Rochester Gas and Electric Company

Allan W. Anderson, Jr., David B. Ward and *Jeffrey Kirk* for Western Kentucky Gas Company

Glenn W. Letham and *Kenneth M. Albert* for Pennsylvania Gas and Water Company

Frank P. Saponaro, Jr. and *Jennifer E. K. Walter* for UGI Corporation

William R. Mapes, Jr. for Equitable Gas Company

Frederick Moring for Associated Gas Distributors

James K. Morse for Northern Indiana Public Service Company

Julia T. Wilson for the Public Service Commission of Maryland

L. William Low, Jr. for Boston Gas Company

Robert F. Shapiro for American Paper Institute, Inc.

Robert C. Platt for Independent Petroleum Association of America

Edison Keener for The Peoples Natural Gas Company

Margaret Ann Samuels and *Jerry K. Kasai* for the Office of Consumers' Counsel, State of Ohio

Robert I. White for Western Gas Marketing U.S.A. Ltd.

Rose T. Lennon for Washington Gas Light Company

Allen C. Wesolowski for Illinois Commerce Commission

Jane DiRenzo Segraves and *Philip Endom* for United Gas Pipe Line Company and Natural Gas Pipeline Company of America

Peter G. Esposito for Cheney Energy Corporation

John W. Ebert for Transcontinental Gas Pipe Line Corporation

Jeffrey T. Sprung for Citizens Energy Corporation

Robert P. Haynes, III for Pennsylvania Office of Consumer Advocate

Gail Thomas for Niagara Mohawk Power Corporation

Donald K. Dankner for Central Hudson Gas & Electric Corporation

Daniel J. Kortum for Equitable Resources, Inc.

Leslie B. Enoch, II and *Jerry W. Amos* for Nashville Gas Company, a Division of Piedmont Natural Gas Company

Thomas R. Sheets for Texas Eastern Gas Transmission Corporation

Harry E. Watson for Transamerican Natural Gas Corporation

Richard E. Kelly, Robert L. Woods and *Sandra J. Delude* for the Staff of the Federal Energy Regulatory Commission

TABLE OF CONTENTS

I. Introduction
II. Statement of the Case
III. The Commission's Proposed Policy Statement
IV. Were Tennessee's Actions Prudent?
  A. Introduction
  B. General Background
  C. Tennessee's Problems with Take-or-Pay
  D. Tennessee's Actions to Correct Its Take-or-Pay Problems
V. Tennessee's Proposed Funding Mechanisms
VI. Objections to Tennessee's Proposal
VII. Answers to Commission's Questions
VIII. Conclusion

I. Introduction

On June 3, 1986, Tennessee Gas Pipeline Company, a Division of Tenneco Inc. (Tennessee), filed Second Revised Volume No. 1 of its FERC Gas Tariff, to be effective July 3, 1986. The asserted purpose of the revised tariff sheets was to implement rates, terms, and conditions of service under which Tennessee would perform open access transportation services pursuant to this Commission's Order No. 436 [*FERC Statutes and Regulations, Regulations Preambles 1982-1985* ¶ 30,665]. A principal element of the terms and conditions under which Tennessee proposed to provide open access service was a mechanism for direct billing of past and future take-or-pay "buy-out" and contract reformation costs.

The proposed Tennesee direct billing mechanism is contained in three Articles of the revised tariff sheets. Article XXX provides for recovery of past take-or-pay costs related to periods from January 1, 1981 through July 1, 1986. Article XXXI provides for recovery of future take-or-pay costs related to periods from July 1, 1986 through December 31, 1989. Article XXXII provides for recovery of lump-sum payments made to producers before December 31, 1990 in return for modifications in the pricing or take-or-pay terms of Tennessee's gas purchase contracts. Each of the three proposed Articles provides for allocation of 80 percent of the applicable costs among Tennessee's customers, with Tennessee to absorb the remainder, and Article XXXIII includes a cap of $200 million on Tennessee's annual recovery of contract reformation costs. Tennessee has agreed to forego any recovery of affiliate take-or-pay and contract reformation costs, which presently approximate $1 billion.

Articles XXX and XXXI provide for allocation of take-or-pay costs among Tennessee's customers based at least in part on a measure of deficiencies of their purchases below certain levels. Article XXX provides for apportionment of past take-or-pay costs among Tennessee's custom-

ers based on a formula providing equal weight to each of three factors: (1) each customer's annual quantity limitation (AQL) for the years 1981 through 1985 as a percentage of the total AQLs of Tennessee's customers for those years; (2) the amount by which a customer purchased below 82 percent of its AQLs for the period 1981 through 1985, in relation to total customer purchase deficiencies below 82 percent of total system AQL; and (3) the reduction in a customer's annual purchases in the period 1983-85 from its annual purchase levels in 1981-82, relative to the systemwide reduction in purchases over the same period. Article XXXI would base the allocation of Tennessee's future take-or-pay costs among customers on deficiencies below a given percentage of each customer's AQL (with the applicable percentage being: 75 percent for the period July 1, 1986 through December 31, 1987; 60 percent for 1988; and 50 percent for 1989). Article XXXII does not use a deficiency-based mechanism, but instead would allocate contract reformation costs each each year based on the customer's AQL as a percentage of the total AQLs of Tennessee's customers.

Numerous parties intervened and filed protests or requests for suspension or hearing in response to Tennessee's revised tariff sheets. *See Tennessee Gas Pipeline Co.*, 36 FERC ¶ 61,032, at p. 61,071 (1986). Intervenors argued that the proposed direct billing of take-or-pay costs related to past periods would constitute unlawful retroactive ratemaking, that targeting of take-or-pay costs based on purchase deficiencies below certain levels would effectively resurrect Tennessee's variable-cost minimum commodity bill, which the Commission had outlawed in Order No. 380 [*FERC Statutes and Regulations, Regulations Preambles 1982-1985* ¶ 30,571], and that tracking of take-or-pay costs, as would occur under Articles XXX, XXXI and XXXII, was contrary to Commission regulations and longstanding Commission policy. It was asserted that the proposed tracking of Tennessee's past and future take-or-pay costs would effectively eliminate cus-

tomer market choice, distort market signals, penalize customers following least-cost purchasing practices, unduly discriminate among Tennessee's customers, and provide Tennessee with an anticompetitive advantage relative to pipeline competitors who were not authorized to direct-bill take-or-pay costs. It was also argued that Tennessee's proposed direct billing mechanism, as opposed to traditional commodity rate treatment of take-or-pay costs, would provide strong incentives for producers to take adamant negotiating postures towards Tennessee, while leaving Tennessee little incentive to bargain hard, due to their mutual awareness that Tennessee would be able to pass a large part of its buy-out costs through to its customers.

On July 2, 1986, the Commission issued an order [36 FERC ¶ 61,032, *supra*] accepting for filing and suspending many of the revised tariff sheets, but rejecting the revised tariff sheets containing Tennessee's proposed direct billing mechanism for take-or-pay costs. In rejecting Tennessee's direct billing proposal, the Commission found that "for the most part, the objections to Tennessee's take-or-pay tracking proposal are well-taken."

The Commission's order identified a number of basic flaws in Tennessee's direct billing proposal. The Commission recognized first that proposed Articles XXX, XXXI, and XXXII were "intended to permit Tennessee to track specific costs without the necessity of filing a rate case." The Commission noted that its rules "specifically" prohibit such tracking of costs, and explained the basis for that prohibition:

> The Commission has repeatedly held that just and reasonable rates are based on review of *all* costs. Trackers permit the isolation of certain cost components and therefore are contrary to Commission policy regarding the setting of just and reasonable rates.

Id. at p. 61,075 (emphasis in original) (footnote omitted).

The Commission also acknowledged the retroactive nature of Articles XXX and XXXII, noting that they "relate to contract liabilities incurred prior to July 1, 1986, and therefore can have no connection with a customer's decision after that date to use Tennessee as a transporter." *Id.* The Commission found that Article XXXI "also is no supported":

> It provides no method for separating those incremental take-or-pay costs, if any, that are caused by a particular customer's decision to become an open access shipper rather than a gas purchaser from take-or-pay costs caused by the current supply/demand imbalance on Tennessee's system. The latter costs may not be appropriate for inclusion in Tennessee's rates at all. Tennessee's own purchasing practices may have led, in part, to the latter situation.

Id.

The Commission nonetheless set Tennessee's direct billing proposal for "a full hearing . . . on all issues regarding Tennessee's take-or-pay and buy-out proposal," including but not limited to the issues that had been raised in the protests and interventions. *Id.* at p. 61,086. "[A]gain without intending to limit the scope of the issues to be addressed at the hearing," the Commission directed that the following specific issues be addressed and resolved:

> 1. Would Tennessee's having a tracking treatment for purchase gas costs without having a comparable tracking treatment for take-or-pay and buy-out costs skew Tennessee's incentives to contract appropriately such that a truly least-cost supply is not achieved?
>
> 2. If Tennessee had trackers for both gas purchases and take-or-pay costs, would these "trackers" cause Tennessee's management to devote too few resources to minimizing of gas costs?

3. Should Tennessee develop a separate service for those customers who wish "backup" or "peaking supplies as an addition to the traditional service of providing base load supplies?

4. Must take-or-pay buy-out costs be billed as part of Tennessee's total gas supply costs—in the commodity cost component of its rates—for accurate price signals to be observed?

5. Is reliance upon the commodity charge to reflect all costs of gas supply an appropriate basis for the allocation of the risk of gas acquisition costs among Tennessee and its various customer classes?

Id.

II. Statement of the Case

This proceeding involves Tennessee's proposal to bill its customers directly for the cost of take-or-pay payments incurred by Tennessee under its gas supply contracts with producers and for the cost of reforming those contracts. Take-or-pay provisions require the pipeline to take delivery of or pay for a minimum quantity of gas. In return, the producer dedicates his gas reserves to the pipeline for the term of the contract. The contracts typically allow the pipeline to "make up" or recover its take-or-pay payments (or prepayments) by taking from the producer within a specified time period the volumes previously paid for but not taken. The Commission recognizes the pipeline's outstanding balance of unrecovered prepayments as an asset includable in the rate base upon which the pipeline is permitted to earn its authorized rate of return.

During the past few years, natural gas markets and the Commission's regulations governing pipelines have changed dramatically. The industry has swung 180 degrees from the gas shortage of the mid-1970s to the gas surplus of the mid-1980s. The Commission, at the same time, has afforded pipeline customers additional flexibility

to purchase from alternative suppliers without relieving the pipelines of their longstanding obligations to stand ready with the gas supply necessary to meet the customers' firm requirements as the need arises.

Because Tennessee and other pipelines executed many of their gas purchase contracts when the industry was just emerging from curtailment and before the Commission changed its regulations, and because customers and pipelines foresaw continued strong demand for gas, those contracts have not been responsive to the gas surplus and the new, intensely competitive market environment. Faced with gas deliverability far in excess of current market requirements, Tennessee and other pipelines' take-or-pay exposures have risen into the billions of dollars. This has prompted Tennessee and other pipelines to negotiate with producers to (1) buy out accumulate take-or-pay liabilities by making nonrecoupable payments in lieu of prepayments that could be made up, at a fraction of the corresponding recoupable prepayment liability, and (2) pay the producers to reform gas purchase contracts to improve take-or-pay and other contract provisions prospestively. The Commission has also promoted take-or-pay buy-outs and contract reformations by issuing policy statements suggesting that pipelines be permitted to recover some of these costs from their customers.

The basic issue here is who pays for these take-of-pay and contract reformation costs. Through its Articles XXX, XXXI and XXXII filings, Tennessee has proposed to share these costs with its customers and to assign the customers' share of the costs to those customers who are responsible for and benefit from them based on the principal factors that caused Tennessee to incur the costs. Others propose to include these costs in Tennessee's commodity rates which will be paid only by those customers who purchase gas in the future.

An issue of major importance in this proceeding is whether Tennessee's gas acquisition and supply management practices have been prudent, that is, whether Tennessee's take-or-pay exposure and need to reform its gas purchase contracts are attributable to changed markets and regulations or to imprudent practices by Tennessee. Certain intervenors have accused Tennessee of acquiring excess gas supplies, failing to negotiate flexible, market-responsive gas purchase contracts, or not acting quickly enough to control its take-or-pay exposure. Tennessee has submitted that it acquired only enough gas supplies to meet reasonable forecasts of its customers' requirements, forecasts that were made in the first instance by the customers themselves and then corroborated by Tennessee. Tennessee has attempted to show further that its gas purchase contracts were executed during a strong seller's market and, as such, contained the terms to which Tennessee and virtually all major pipelines had to agree to obtain the dedication of long-term gas supplies from producers. Finally, Tennessee has sought to demonstrate that it took appropriate action to control take-or-pay as market conditions and regulatory policies changed after Tennessee had already executed its gas purchase contracts in reliance on a different set of expected conditions.

In response to hundreds of discovery requests, Tennessee produced all of its 1,600 gas purchase contracts, as well as thousands of pages of related material on Tennessee's gas purchasing and marketing strategies, take-or-pay, and other subjects explored by the parties. Tennessee, the Commission Staff, and numerous intervenors submitted prepared testimony and exhibits. Hearings commenced on December 8, 1986 and concluded on January 16, 1987, culminating in more than 2,700 pages of transcript, in addition to thousands of pages of prepared testimony and hearing exhibits. Helpful briefs have been filed.

III. The Commission's Proposed Policy Statement

On March 5, 1987, after the hearing in this case had ended and shortly before the initial briefs were due, the Commission issued a proposed Policy Statement on recovery of take-or-pay, buy-out and buy-down costs. *See* 38 FERC ¶ 61,230 (1987). The Commission directed that public comments on its proposed Policy Statement be filed on or before April 10, 1987.

The Commission's proposed Policy Statement would establish guidelines allowing natural gas pipelines to recover in their demand rates costs incurred to reduce or extinguish existing take-or-pay liabilities, to terminate contracts, or to reform the price, volume, or other economic terms of their contracts. To qualify for such treatment, a pipeline would have to agree to an "equitable sharing" of the buy-out or buy-down costs, which the proposal posits as a 50-50 sharing of the costs between the pipeline's shareholders and customers. The pipeline would allocate the 50 percent of the costs to be passed through in its demand rates among its customers based on a formula assessing each customer's cumulative purchase "deficiencies" relative to purchases during a "representative base period" preceding the onset of the pipeline's take-or-pay problems. The proposed Policy Statement would be applied to ongoing rate proceeidngs "if a pipeline so chooses, subject to approval of the presiding judge."

It is by no means clear that the Commission will adopt any new policy for dealing with take-or-pay, much less that the draft Policy Statement will be adopted in anything like its present form. Three Commissioners have expressed varying degrees of reservations about the proposal, and the Commission presumably will take to heart the public comments it receives before issuing any final policy statement. Moreover, even if the general structure proposed in the draft Policy Statement is retained by the Commission, some important modifications and clarifications are likely. It is also highly uncertain whether any

new policy would be applicable to this proceeding. It is not at all clear that Tennessee will request treatment under its terms. At a posthearing conference on March 20, 1987, counsel for Tennessee was unable to state whether Tennessee would request such treatment if it were adopted in its present form.

In any event, even if the Policy Statement were to be applied in this proceeding in its present form, it would not dispose of many critical issues, including the issue of the prudence of Tennessee's incurrence of take-or-pay liabilities. There is thus great uncertainty whether the Policy Statement will be adopted in its present form or whether it could be applied here at all. Unless and until there is a final Policy Statement, a timely decision by Tennessee to invoke it, and approval of that decision by the presiding judge, Tennessee's proposal must be judged on the basis of the Commission's existing policies regarding recovery or take-or-pay costs and the massive record assembled in this proceeding.

IV. Were Tennessee's Actions Prudent?

A. Introduction

Under Section 4 of the Natural Gas Act, 15 U.S.C. § 717c (1982), natural gas prices charged by pipelines must be "just and reasonable." In *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), the Supreme Court stated that the Act's "primary aim . . . was to protect consumers against exploitation at the hands of natural gas companies." 320 U.S. at 610. The Act serves as a "complete, permanent and effective bond of protection from excessive rates and charges." *Atlantic Refining Co. v. Public Service Commission*, 360 U.S. 378, 388 (1959).

While the "just and reasonable" standard is not susceptible of precise definition and the Commission is to "evaluate all factors bearing on the public interest," *Public Service Commission v. FPC*, 543 F.2d 757, 785 (D.C.

Cir. 1974), it is firmly established that pipeline costs which are not *prudently incurred* are not just and reasonable. *See Metzenbaum v. Columbia Gas Transmission Corp.*, 4 FERC ¶ 61,277 (1978). It is the standard of prudence against which Tennessee's gas purchasing practices are to be measured in this case, and the burden of proof is on Tennessee to show that its practices satisfy the test.

A threshold question in any proceeding such as this, in which a pipeline's purchasing practices are under scrutiny, is the definition of the prudence standard. The standard is a "reasonable man" standard. Prudently incurred costs are those "which a reasonable utility management . . . would have made, in good faith, under the same circumstances, and at the relevant point in time." *New England Power Co.*, 31 FERC ¶ 61,047, at p. 61,084 (1985).

In this proceeding the central question is whether Tennessee was prudent, given the information available to it at the time, in entering into gas supply contracts under which it has incurred great financial exposure for gas it may not be able to purchase and resell. "The Commission has traditionally placed the primary responsibility for a long-term balancing of gas supply and demand upon the interstate pipelines." *Transwestern Pipeline Co.*, 22 FERC ¶ 61,172 (1983). We must address how well Tennessee discharged its "primary responsibility," how well it determined its future needs for gas supply, how well it assessed market risk, how well its contracts reflected market risk, and how well it responded when the first signs of trouble appeared.

Thus, it is Tennessee's burden to prove that its purchasing practices have been prudent and that the costs it proposes to pass through are reasonable. In order to survive scrutiny, Tennessee's take-or-pay costs must be both prudently incurred and reasonable in amount. More-

over, the procedural history of this particular case makes its burden even heavier. The Commission did not accept this filing, and suspended it subject to refund. It considered the challenges raised by numerous intervenors, it refused to waive its regulations, and it concluded that the filing must be rejected. The hearing ordered by the Commission was to give Tennessee an opportunity to overcome this finding. 36 FERC at p. 61,076.

In my judgment, Tennessee has indeed overcome this finding and has successfully carried the heavy burden of proving that its actions at the relevant times were prudent.

B. *General Background*

Take-or-pay issues are widespread in the natural gas industry. They represent an interaction of economic and regulatory activity since the 1970s, when inadequate gas supplies were dedicated to interstate commerce. The resulting curtailments prompted many pipelines to enter into long-term contracts with producers at high prices, under which pipelines agreed to make payments to producers whether or not gas was actually taken. Most of these agreements were negotiated between 1979 and 1982.

When demand began to soften soon after this time, pipelines sought relief from take-or-pay provisions by simply refusing to make payments, be renegotiating, or by buying out or buying down producers' take-or-pay claims. Pipelines' total liability for take-or-pay has been estimated at $8 billion. 38 FERC at p. 61,725.

The Commission has required that pipelines recover the costs of these measures prospectively through the commodity sales rate, if at all. *See Transcontinental Gas Pipe Line Corp.*, 37 FERC ¶ 61,089 (1986); *Trunkline Gas Co.*, 37 FERC ¶ 61,201 (1986). Many pipelines, including Tennessee, have objected that this rate treatment renders their gas unmarketable because their competitors

offer plentiful, less expensive supplies. *See* 38 FERC at p. 61,730 n.6.

Since 1984, the Commission has issued several orders which potentially affect take-or-pay issues. In Order No. 380, the Commission eliminated variable costs from minimum commodity bills in pipelines' sales tariffs. *See* 49 Fed. Reg. 22,778 (June 1, 1984), *FERC Statutes and Regulations, Regulations Preambles 1982-1985* ¶ 30,571 (1984), *aff'd in relevant part, Wisconsin Gas Co. v. FERC*, 770 F.2d 1144 (D.C. Cir. 1985). This rule relieved pipelines' customers of commitments to pay for gas not actually taken from their pipeline suppliers.

In 1985, the Commission issued a Statement of Policy on the regulatory treatment of one-time payments made by pipelines in return for producers' waiver of take-or-pay obligations. *See* 50 Fed. Reg. 16,076 (Apr. 24, 1985), *FERC Statutes and Regulations, Regulations Preambles 1982-1985* ¶ 30,637 (1985). Under this policy, pipelines may seek recovery of these payments in a Section 4(e) rate filing, but not in a Purchased Gas Adjustment proceeding.

In Order No. 436, the Commission required pipelines to offer transportation on a non-discriminatory basis in order to be eligible to transport any gas at all under the Commission's blanket certificate program. *See* 50 Fed. Reg. 42,408 (Oct. 18, 1985), *FERC Statutes and Regulations, Regulation Preambles 1982-1985* ¶ 30,665 (1985), *vacated and remanded sub nom. Associated Gas Distributors v. FERC*, No. 85-1811 (D.C. Cir. June 23, 1987). The Commission rejected pipelines' requests that producers be required to waive take-or-pay claims as a condition of obtaining non-discriminatory transportation. 50 Fed. Reg. at 42,433-34.

In Order No. 451, the Commission eliminated vintage-based pricing of old gas, in an attempt to match the price of all gas to the commodity value in a competitive market.

See 51 Fed. Reg. 22,168 (June 18, 1986), *FERC Statutes and Regulations* ¶ 30,701 (1986). This order requires producers to use a "good-faith negotiation" procedure in seeking non-vintage prices from pipelines.

Finally, as we have seen, the Commission has issued a proposed Policy Statement on buyout and buy-down costs incurred by pipelines. *See* 38 FERC at p. 61,724. In this proposed Policy Statement, the Commission states that a pipeline should be allowed to collect 50 percent of such costs through its demand charge, and absorb the other 50 percent. *Id.* at p. 61,727. In addition, the Commission states that take-or-pay issues represent "the last and most significant deterrent to the realization of the Commission's goal of removing, as far as possible, obstacles to the establishment of orderly, competitive markets for natural gas sales and services." *Id.* at p. 61,726. Resolution of the issues in this case, then, requires an attentiveness to the marketplace in general, as well as to Tennessee and its suppliers and customers.

C. *Tennessee's Problems with Take-or-Pay*

Tennessee's experience with take-or-pay resembles that of the pipeline industry generally. Tennessee, like so many others in the industry, was forced to curtail service to its customers for several years because of the gas shortages in the 1970s. In fact, Tennessee did not emerge from curtailment until 1980 and would have had to curtail again in 1981 but for the purchase of up to 800 MMcf per day on the spot market to meet its customers' peak demands.

It was natural for the pipeline's management to seek to purchase additional quantities of gas so as to satisfy the continuing demand for service. Under these circumstances, producers exacted a heavy toll from Tennessee and others in the industry for the privilege of committing their production to one or another pipeline. One of the tolls exacted was the imposition of severe take-or-pay con-

ditions coupled with high prices in contracts executed during the period 1978-1981.

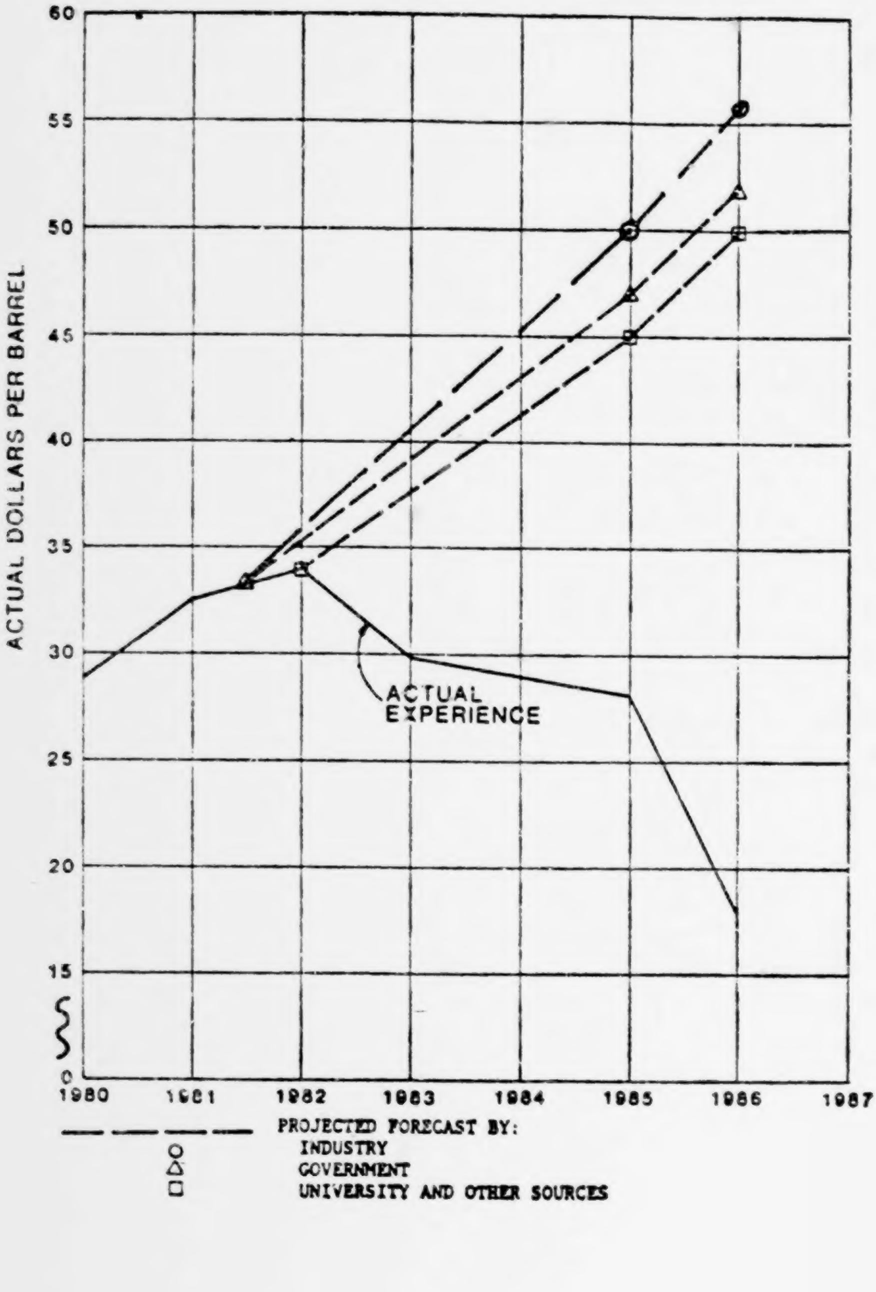
At that time Tennessee was also handicapped by a relatively low Reserve Life Index (RLI) which ranged from 7.4 years to 7.9 years of supply when the industry average varied from 9.2 to 9.6 years. Tennessee could be expected, indeed was required, to seek to overcome a weak RLI by an aggressive acquisition program which it adopted and followed. Not only was its RLI weak, its supplies were composed in large part of reserves in off-shore Gulf Coast gas fields which historically have been depleted rapidly. This led Tennessee to seek reserves in other aras.

Tennessee's experience with curtailment, the pressure of a sellers' market for gas, and a low RLI grounded in rapid depletion areas all contributed to that pipeline's attitude and approach to the acquisition of new sources of gas supplies. In *Northern Natural Gas Co.*, 16 FERC ¶ 61,109, at p. 61,244 (1981), the Commission said:

> Pipelines must continue to purchase long-term gas supplies. For example, at present many interstate pipelines rely upon the large, high-deliverability gas fields in the Gulf Coast as a principal supply source. Because this source is projected by the pipelines to decline significantly after 1985, new gas sources must be developed to assure adequate supplies for the future.

And what were the experts predicting about the future of energy supplies? The following graph introduced into evidence by Tennessee through witness Sherman H. Clark dramatically portrays what most industry, government and university sources were forecasting in 1981 for crude oil prices in subsequent years as compared to actual experience:

FIGURE 4 MEDIAN OF CRUDE OIL PRICE FORECASTS AS OF 1980-1982 MADE BY INDUSTRY, GOVERNMENT, UNIVERSITY AND OTHER SOURCES VERSUS ACTUAL EXPERIENCE



As seen, the expectation was for crude oil prices to continue their upward course through 1986. Gas prices were expected to rise accordingly. Unfortunately for Tennessee and the pipeline industry, the bottom fell out of the energy markets and oil prices dropped precipitously as shown on the graph. New gas prices followed suit.

The parties have expended a great deal of effort in developing the crucial subject of the foreseeability of market decline for natural gas beginning in late 1981 or early 1982. In my view, the evidence of record in this proceeding overwhelmingly supports Teneseee's position that most forecasts and most forecasters at the time predicted a continuously rising market for gas throughout the 1980s and well into the 1990s. Tennessee's expectations were in this mainstream of forecasts. Tennessee made these projections based on an analysis of customer surveys by its Customer Relations and Marketing (Marketing) Department and on an analysis of price, supply, and demand projections by its Economic Analysis and Long Range Planning (EALRP) Department.

In performing and evaluating customer surveys during 1979-1982, Tennessee relied on personnel from its Marketing Department, who had over 100 years of cumulative experience in gas marketing and customer relations, and had intimate knowledge of Tennessee's customers, their markets and competitive fuels. These Tennessee employees made a concerted effort to maintain close contact with the Tennessee customer community through numerous individual meetings, phone conversations, and annual meetings where Tennessee's gas acquisition strategy was explained and where Tennessee would respond to any concerns that customers might have about gas prices or other factors that might affect their purchase levels. Tennessee Marketing Department personnel also visited industrial customers who purchased either directly or indirectly from Tenneseee's customers, studied the loads of Tennessee's customers and the loads of their industrial

and power plant customers, and monitored oil prices in each customer's service area on a monthly basis.

Tennessee's personnel were thus able to evaluate customer responses to surveys and determine what, if any, adjustments needed to be made to those surveys to provide a reasonable projection. Tennessee did not rely only on customer surveys to predict future demands. Its EALRP Department reviewed energy forecasts from consulting firms in the business, produced its own forecasts, participated in conferences contacted forecasters from other energy companies, and reviewed government energy forecasts before finalizing a demand forecast. The participation of Tennessee's EALRP department in forecasting demands was significant because that department has been recognized as an industry leader in forecasting energy supply and in demand and price forecasts.

In 1979, forecasters generally predicted $30-$40 per barrel oil prices by 1985, with those prices increasing steadily through 1990. In 1979, the Department of Energy (DOE) forecast prices as high as $62.79 per barrel in 1990. In 1980-1982, both government and industry forecasters predicted even greater increases in oil prices with numerous forecasters predicting prices of $50 or more per barrel for oil in 1985 and over $70 per barrel for oil in 1990, with some forecasters predicting oil prices in excess of $100 by 1990. By 1980, DOE predicted oil prices of $49 for 1985 and $84 for 1990, and in early 1982, DOE predicted oil prices of $38-$56 per barrel for 1985 and $72-$103 per barrel in 1990. The graph shown above depicts the scene for the period 1980-1986.

Administrative Law Judges in other prudence cases have recognized repeatedly that the expectation of substantial increases in oil prices was the general industry and government view during the immediate post-Natural Gas Policy Act (NGPA) era. In *Panhandle Eastern Pipe Line Co.*, 34 FERC ¶ 63,055, at p. 65,187, (1986), Judge

Leventhal found that in the early 1980s, "the almost universal expectation [was] that the price of a barrel of oil would be almost $60.00 by year 1985." Judge Miller in *Trunkline Gas Co.*, 32 FERC ¶ 63,018, at p. 65,027 (1985), found that "[c]rude oil forecasts made during 1979-1982 by the American Gas Association (AGA) and [DOE's] Energy Information Administration (EIA) were for the price to go in nominal dollars per barrel from about $30 in 1981 to between about $80-$100 by 1990." Although gas was expected to remain cheaper than oil through at least 1985, the industry forecast continued substantial increases in natural gas prices. This was a basic premise of the NGPA, which deregulated new gas supplies and incorporated an escalation provision in its gas pricing formula, automatically increasing the price of regulated gas monthly. *See generally* 16 U.S.C. §§ 3311-3320 (1982) (wellhead price controls).

Judge Miller further found that in 1980 the AGA and EIA forecasted 1990 gas prices to $8 to almost $11 per Mcf in current dollars, and that "[a] 1981 EIA study, released in February 1982, projected that residential gas prices would average $6.00/Mcf in 1985 and $10.70/Mcf in 1990." 32 FERC at pp. 65,027, 65,030. Based on these oil and gas price forecasts, it "simply was not anticipated in 1981 that gas prices would not remain competitive with oil prices until 1985 gas decontrol went into effect." *Panhandle*, 34 FERC at p. 65,188.

This Commission recognized that "[t]here was a general belief [in the early 1980s] that oil prices would continue to rise and that there would be continued demand for natural gas since it was still on average underpriced." *See* Notice of Inquiry, Impact of Special Marketing Programs on Natural Gas Companies and Consumers, 49 Fed. Reg. 3193 (Jan. 26, 1984), *FERC Statutes and Regulations* ¶ 35,513, at p. 35,584 (1984). Thus, consistent with the competitive position of natural gas vis-a-vis oil, the industry consensus was that nationwide natural gas

demand would remain strong, constrained only by the supply.

The expectation of strong future demands is further shown by the demand forecasts from the immediate post NGPA period. The median projection from 1978-1982, based on 31 published forecasts from government and private sources, was for U.S. natural gas demand of 20.8 Tcf in 1985 and 22 Tcf in 2000. DOE in 1981 and 1982 projected demands of around 20 Tcf for both 1985 and 1990. Judge Miller in *Trunkline* found that "[e]nergy economists were forecasting a U.S. demand for natural gas in excess of 20 Tcf for the mid-1980s and beyond." 32 FERC at p. 65,029.

Notwithstanding these forecasts of rising prices, experts in the field did not anticipate a growing supply resource base. To the contrary, during the early 1980s, the consensus was that the availability of supplies from conventional (lower-48) sources would become substantially more limited in the future. Pipelines were, thus, provided with the incentive to acquire any supplies when they were available in the immediate post-NGPA era. For example, Shell and Exxon during this time period estimated future decreases in conventional lower-48 supplies. Further, in *Trunkline*, Judge Miller stated that:

> In 1979 several major natural resource companies and the EIA and General Accounting Office were forecasting gas production in the lower 48 states from conventional sources from about 18 to 19 Tcf per year in 1980 to a range of about 14 to slightly lower than 18 TCF by 1990.

32 FERC at p. 65,027.

In sum, based on the above generally expected future conditions, pipelines, including Tennessee, needed to seek increasingly more expensive gas supplies during the immediate post-NGPA period because of expected strong future demands and the reasonably-based fear that suf-

ficient supplies would not be available in the future, a fear that was magnified by the industry's recent curtailment experiences of the 1970s. Moreover, based on the above expectations, the industry reasonably anticipated selling the natural gas purchased at even increasing higher prices.

Intervenors and Staff vigorously attack these findings, asserting that the slide in natural gas demands could have and should have been foreseen by Tennessee. For example, the New England Customer Group points to two "smoking guns," statements of two of Tennessee's top officials who analyzed the causes of the company's take-or-pay problem. The first statement, an internal house memorandum, was made on September 29, 1982 by J. E. Ramsey, a vice-president and a chief witness in this case. Ramsey decried the company's purchasing policies, which he blamed for the continued rapid increase in gas costs. He also said:

> . . . We continue to pay high prices for new deregulated gas contracts when practically no one else is doing so. We have not chosen to exercise our market outs where it coud be done, and although the impact will be minimal on our purchase gas cost, the PR impact with customers and the commission is very large . . . .
>
> To elaborate on the risks of guessing wrong, if we essentially curtail our gas acquisition activity and, for some reason which I cannot fathom, our market does turn strongly upwards, we could face some very minor curtailments by 1985. On the other hand, if we continue to buy gas with fairly quick deliveries and the market is even weaker than the base case forecast, the potential take-or-pay exposure that we will face with producers is, as you know, staggering . . . . The key today and for the next few years is deliverability, management. If we cannot show the need for deliverability, we should not buy any reserves unless we have zero to take-or-pay requirements. . . .

> I still believe our current objectives and assumptions are internally inconsistent and impossible to obtain. I would very much like to talk with you on this subject.

The memorandum was addressed to the President of Tennessee Gas Transmission (Tennessee's predecessor). See Ex. BCN-8.

The second document is a speech given by J.B. Foster, who has been Executive Vice President of Tenneco, Inc. (Tennesee's parent since 1981. On April 12, 1983, he gave a speech at the University of Houston which he titled, "Why Were So Many So Wrong About So Much?" One thing that went wrong was the apparent adoption of something Foster labeled "groupthink," which replaced independent critical thinking, and which is likely "to result in irrational actions directed at out-groups." Another thing wrong was the presence of the "competition complex," which led a big company like Tenneco to compete by outbidding others "for a lease or a rig or a geologist." Foster also said:

> I remember having many nagging doubts at the peak of the boom. I felt, "This is crazy. It can't go on." But it is hard to fly in the face of the whole industry. It is hard not to compete. We cut back some, but not enough . . . . Remember the "Noah Principle":—"Predicting rain doesn't count, building Arks does."

Ex. LAG-29 at 13-14, 18-21, 24.

I don't see much smoke coming out of the Foster gun. His 1983 speech seems largely theoretical soul-searching by an executive trying to see in retrospect why he had not predicted the fall in energy demand two or three years before. I don't think he should feel so badly about this since most all his peers were making the same predictions, all of which proved to be erroneous.

There is smoke in the Ramsey memorandum which may be read as a "confession," as contended by New England, because of the stated indictment of Tennessee's policies on September 29, 1982. Or it can be read as one day's musings of an executive who was considering Tennessee's acquisition policies and expressing his personal views about those policies on that day. Certainly, Ramsey did not continue to harbor his stated criticism. In this proceeding he was a leading witness who produced hundreds of pages of written testimony and who was subjected to days of searching cross-examination. Having reviewed all this evidence, and having observed the demeanor of the witness on the stand, I find that Ramsey's testimony was not only believable but convincing that Tennessee's acquisition policies at the time were fair and reasonable, the smoking gun memorandum notwithstanding.

Tennessee's opponents allegedly have found another smoking gun or guns in interoffice memorandums written by William A. Johnson, chief economist for Tenneco. Many of these documents expressed Dr. Johnson's views that energy demands were weakening in the late 1970s and early 1980s. For example, in April 1980 he wrote:

> In fact, the United States is now experiencing a "gas bubble" which is backing domestically produced gas out of the U.S. market.
>
> Perhaps more significant, U.S. demand for gas has slowed significantly, in part, because of conservation and, in part, conversion to alternative fuels.
>
> It is arguable that this "bubble" will continue for a number of years.

Ex. GLD-1 at 35.

Similarly, in August 1980, in addressing the question "Is demand for interstate gas sufficiently high, and the supply of interstate gas from conventional sources sufficiently low, to justify major investments in supplemental gas projects?" Dr. Johnson wrote:

> The underlying reason for lower than anticipated demand for natural gas in the interstate market has been the shift out of gas by some utilities and industrial users.
>
> Theoretically, TGT's curtailment rate for firm requirements is about 18%. However, this rate is based upon 1973 contract volumes. It is unrealistic to assume that customers that have been curtailed for a significant period of time will once again demand gas if and when that gas becomes available. Many of these customers are probably no longer in the market.

Id. at 36.

In a November 26, 1980 Memorandum to S. D. Chesbro, Corporate Planning & Development, on the subject "Probable Impact of the 1980 Elections on Tenneco's Business," Dr. Johnson wrote:

> *Tennessee Gas Transmission* should experience more rapidly rising prices and continued weakness in demand for natural gas. The gas bubble will last for several years, possibly prompting legislation to ease requirements that industrial users appear to have begun conversion already [*sic*]. The process may, to some extent, be irreversible. A revision of the Natural Gas Policy Act could also result in greater inducements to exploration and production for new gas. These events portend continued difficulties for TGT in selling the volumes that it is able to deliver through its pipeline system. They also call into question the economic viability of high cost supplemental sources not subsidized one way or another by the U.S. government.

Id. at 37 (emphasis in original)

Tennessee rejected Dr. Johnson's conclusions—with ample reason. The consensus among most forecasters, including Tennessee's customers, was that demand would exceed supply. Rather than risk curtailment again, Ten-

nessee and many other pipelines chose to continue acquiring supplies. Ex. JER-8 at 7-8. This decision is defensible in light of the weight of authority at the time. It is also defensible in view of Dr. Johnson's shortcomings as an analyst. For example, in an April 1979 paper (Ex. WRH-18), it is unclear whether he believes surplus or shortage is imminent. *See* Ex. SHC-14 at 23-24. In another document (Ex. GLD-19 at 18), he predicts that Tennessee's reserves will be enhanced by supplies from the Atlantic Outer Continental Shelf. In fact, relatively few supplies were obtained from that source. *See* Ex. JER-8 at 7-8. Tennessee has shown it relied upon "mainstream" forecasts and upon assessments made by its customers. It has also shown that Dr. Johnson was not infallible in his predictions. It was not imprudent for Tennessee to reject his analysis.

If, *arguendo*, Tennessee fired any smoking gun, some of its opponents in this proceeding also had a finger on the trigger. For example, in 1982 the federal government was continuing to fund the United States Synthetic Fuels Corporation, which would not be economically feasible without extremely high oil and gas prices. Ex. SHC-1 at 32. Apparently Staff, which here contends that Tennessee was imprudent, would require that Tennessee have more foresight than the federal government. Columbia, one of Tennessee's largest customers, would also hold Tennessee to an exalted standard of prudence. In 1982, Columbia's witness in Docket No. TA82-1-21 testified that the "essentially universal . . . view [was] that supplemental, high-cost supplies would be required to meet future demands." Ex. SHC-14 at 10. Similarly, the New England Customer Group was loudly complaining at this time that Tennessee was not expanding its gas supplies to avert future curtailment. *See* Ex. TMM-1 at 9; Ex. JRK-8 at 5. Indeed, the Group opted to acquire substantial long-term supplies of its own at this time. *See* JER-21 at 5.

In my view, the evidence compels a finding that Tennessee made the same decisions that most other oil and gas

companies did, as well as the federal government. These decisions were based upon the vast preponderance of analyses available at the time and were fairly and reasonably arrived at. The fact is that either a pipeline bought gas to meet its service obligations, or those obligations were not met. In so doing, companies such as Tennessee were forced to agree to high prices and contractual terms with producers that the market dictated. These terms included onerous take-or-pay provisions which are at issue here. Yet Tennessee's customers were predicting a continuing rising demand for Tennessee's gas, and producers apparently believed in a sustained demand for their gas as shown by the high level of drilling and capital expenditures which was maintained through 1982. Under these circumstances, to fault Tennessee's conduct as imprudent would amount to Monday morning quarterbacking of the worst sort.

D. *Tennessee's Actions to Correct Its Take-or-Pay Problems*

How well did Tennessee respond when the first signs of trouble appeared? This question was addressed by witness Thomas M. Matthews, President of Tennessee, who underwent intense cross-examination of his rebuttal and surrebuttal testimony. A review of this evidence leads me to conclude that Tennessee did, in fact, act reasonably quickly and aggressively when signs of a decrease in demand for gas appeared. As we have already seen, the expectations in 1981 was for a steadily rising demand for gas into the 1990s. The problem of excess deliverability first arose in 1982. One reason is that demand began to decrease in 1982, and continued to decelerate throughout the next few years to and including 1986. Another reason is that, starting in the second quarter of 1982, many producers increased their supplies not by exploring for and developing new reserves (as was the common practice in the past), but by sinking additional wells in existing reservoirs. Deliverability under existing contracts was

thus increased, and the groundwork was laid for the take-or-pay problem which became a crisis for Tennessee in 1983. By the end of 1986, Tennessee had a take-or-pay exposure of over $3 billion.

Tennessee's sales in 1982 were sufficient to avoid take-or-pay exposure that year. Nevertheless, having discovered the beginnings of an increase in excess deliverability, Tennessee's management throttled back on its purchases of new gas supplies, pulling back outstanding offers where it was possible to do so. In July 1982 the company established a policy under which it would contract for new deliverability only after April 1, 1984, by which time reserves were reasonably expected to be depleted. In fact, Tennessee purchased very little new gas in 1983, 1984 and 1985, and deliverability was substantially decreased between 1983 and 1985. In July 1982 Tennessee also assembled a Supply-Demand Task Force consisting of some 20 study groups formed to analyze the extent of the pipeline's future take-or-pay exposure. The Task Force concluded that adequate measures had been taken.

In November 1982 Tennessee began to exercise its market-outs. These are contract devices which provide pipelines with protection against having to purchase unmarketable gas. This first market-out was at a price of $4.85 effective January 1, 1983. The timing of this move shows that Tennessee was monitoring the situation effectively—only three other pipelines, Transco in May 1982, Michigan-Wisconsin in July 1982, and United Gas in September 1982, marketed out before Tennessee, and Tennessee's price was the lowest up through November 1982. Virtually all the contracts entered into by Tennessee in 1982 contained market-out provisions, most of which were immediately exercisable. For example, the three large contracts booked that year represented about one-half of all new reserves added in 1982 and each of these agreements contained immediately exercisable market-out provisions.

Tennessee then commenced an extensive renegotiation effort with approximately 30 of its major producers. These producers, which supplied about 80 percent of Tennessee's gas, rebuffed the pipeline. To complicate the issue, Tennessee's geographical area experienced a record warm winter in 1982-1983. Demand was further reduced, and Tennessee was forced to cut its takes from producers. Producers reacted by reducing deliveries of low cost gas and maximizing deliveries of high cost gas; consequently, the actual Weighted Average Cost of Gas (WACOG) for 1983 was higher than the forecasted WACOG. In February of that year Tennessee notified its producers that any deliveries in excess of nominations would be priced at 28 cents per MMBtu, the FERC minimum rate.

In May 1983 Tennessee implemented its Emergency Gas Purchase Policy (EGPP), the purpose of which was to reduce and control take-or-pay exposure. This was the first systemwide approach to take-or-pay problems by any pipeline. The policy was based on reduction of purchasing levels of gas and rejection of take-or-pay claims, unless the producer agreed to the EGPP. The implementation of EGPP had the desired effect of substantially reducing the WACOG and the amount of gas purchased. Of the major producers, only ARCO contested the EGPP, while producers accounting for about 75 percent of deliverability agreed to the plan. The EGPP was supported by the company's customers and was incorporated in a November 29, 1983 rate settlement agreement in Docket No. RP77-62, *et al.* The Commission approved this agreement on February 3, 1984, 26 FERC ¶ 61,164. EGPP remained Tennessee's policy until the advent of Order No. 380, when some customers began to swing from Tennessee to other suppliers. By late summer 1985, the company began to focus its takes on lower cost fields and in early 1986 it adopted a least-cost gas purchasing pol-

icy with an absolute least-cost purchasing policy put into place on March 1, 1986.

These actions clearly indicate that Tennessee's management became timely aware of take-or-pay exposure, and took reasonable and appropriate steps to avoid, control and reduce this exposure. While witnesses for New England, Baltimore Gas, Columbia and Staff sought to discredit Tennessee's testimony on this topic, I find such efforts unavailing and overcome by Matthews' surrebuttal testimony in Exhibit TMM-13. The record establishes that Tennessee's opponents rely for the most part on perfect 20-20 hindsight in their criticism of Tennessee's actions. As noted *supra*, Tennessee was only doing what almost all of its peers were doing, including some of the very entities now criticizing Tennessee's performance. Hindsight, however, does not establish imprudence, nor does repeated reference to Dr. Johnson's warnings. *See generally* Exhibits LAG-23; GLD-1; and AMF-21.

The intervenors consistently rely upon hindsight and highly selective evidence in their allegations of imprudence. Staff singles out one contract out of 1600 (Staff I.B. at 42-44), while ignoring contemporaneous governmental predictions of increased gas consumption, and federal funding of the synthetic fuels program. The New England Customer Group cites a 1982 memorandum and a 1983 speech which at most, imply foreseeability of current take-or-pay problems. Several intervenors give great weight to Dr. Johnson's 1980 memorandums, although they contained inconsistencies, and reached conclusions which were contrary to industry consensus. Compared to Tennessee's reasonable forecasts of gas supply and demand, and its later efforts to remedy its take-or-pay problems, these examples of evidence supporting alleged imprudence are insignificant. The totality of the record shows that Tennessee was prudent in incurring its take-or-pay obligations.

V. Tennessee's Proposed Funding Mechanisms

Having determined that Tennessee's gas acquisition practices were reasonable, we now turn to the mechanisms Tennessee proposes to use to recover the costs incurred in funding take-or-pay and contract settlement costs. These mechanisms are found in Article XXX, XXXI, and XXXII of the revised tariff sheets as summarized in the introductory section of this decision.

Under current accounting practices, pipelines are required to treat take-or-pay prepayments as an asset included in Account No. 165, Prepayments. When a pipeline makes up these recoupable volumes for which it has previously made prepayments, it credits Account No. 165 for the value of the made-up gas, and the cost of the gas is included in the appropriate gas purchase account (*e.g.*, Account No. 801, Natural Gas Field Line Purchases). The gas cost is then collected from the pipeline's customers through the Purchased Gas Adjustment (PGA). For ratemaking purposes, prepayments are treated as an element of working capital and are therefore included in the company's rate base. Since take-or-pay prepayments are production-related, they are included in the pipeline's production function, and the return thereon and associated income taxes are classified to the commodity charge of the pipeline's sales rates. The Commission recently reaffirmed and explained the bases of its long-standing policy that production-related costs should be classified to the commodity charge. *Natural Gas Pipeline Company of America*, 25 FERC ¶ 61,176, at p. 61,482 (1983); *Tennessee Gas Pipeline Company*, 36 FERC ¶ 61,071, at p. 61,174 (1986).

On the other hand, non-recoupable payments made to extinguish take-or-pay obligations (i.e., take-or-pay buy-outs), or payments made as consideration for amending the take-or-pay provisions of gas purchase contracts, are included in Account No. 813, Other Gas Supply Expenses. As with recoupable take-or-pay payments, these costs are

considered production-related costs and as such are classified to the pipeline's commodity charge. The costs are generally anortized over a multiyear period.

Tennessee's proposals here are a radical departure from the long-standing Commission policies against tracking and against direct billing mechanisms for recovering these costs. Nonetheless, and despite past Commission findings, the hearing order herein sets these radical proposals for hearing with the obvious objective of taking a new look at the subject. Judge Benkin has blazed a well-reasoned trail in this area in *Transwestern Pipeline Company*, Docket No. RP86-126-000, 39 FERC ¶ 63,025 (1987). While rejecting the specific proposals of Transwestern in that case, Judge Benkin states that "this is an area in which pragmatic adjustments are required, theoretical soundness must occasionally give way to practical considerations, and the task of the Commission is to devise an equitable sharing of the burden of disposing of take-or-pay liabilities among the pipeline and its customers." 39 FERC at p. 65,126.

This view was foretold in two Commission actions in the recent past. The first of these was the proposed Policy Statement issued March 5, 1987, which has already been examined in some depth herein. There the Commission seems clearly to be leaning away from traditional commodity charge treatment in favor of a demand surcharge as a mechanism which will receive approval where the costs have been prudently incurred. And, of course, the Statement contains the suggestion that the equities should balance out at a 50-50 sharing of those costs between the pipeline and its customers. The second Commission action of precedential value was the approval two weeks earlier of a settlement in *Transcontinental Gas Pipe Line Corp.*, 38 FERC ¶ 61,165 (1987), which included provision for a 50-50 sharing of take-or-pay costs between Transco and its customers.

These two Commission actions and Judge Benkin's lucid development of the take-or-pay problem as it now is faced by the agency leads me to conclude that the time has come to permit the sharing of these costs and to permit tracking and direct billing thereof. It is simply not acceptable to continue the practice of assessing take-or-pay costs to the commodity charge where it will impact only those customers who continue to purchase their gas from Tennessee and at greatly increased cost to them. At the same time those customers who shop around and for one reason or another decide to buy their gas elsewhere would avoid all take-or-pay responsibilities under commodity charge treatment. This would be true even though Tennessee under its contract with such a customer remained bound to supply that customer on demand for service. As Judge Zimmet has observed, the issue boils down to whether a non-purchaser should be able to "walk away scot-free from the take-or-pay costs reasonably incurred by [Tennessee] on its behalf, and thereby throw the costs on [Tennessee] itself or other sales customers that continue to purchase gas from the pipeline." *ANR Pipeline Co.*, 38 FERC ¶ 63,048, at p. 65,286 (1987).

One example will demonstrate how devastating commodity treatment would be for Tennessee. Assume that the pipeline can resolve its take-or-pay and contractual problems for a total cost of $1.0 billion and that that amount could be amortized in Tennessee's commodity rate over a three-year period. Based on Tennessee's 1985 sales of 551.1 Bcf, Tennessee's commodity rate would increase by 60 cents per Mcf. That increase alone is almost double Tennessee's current Zone 5 commodity rate of 31.83 cents per Dth. A commodity rate increase of that magnitude could and probably would give multi-supplied customers off the Tennessee system, especially under an open-access scenario. Moreover, major customers for whom Tennessee acquired the gas under the contracts generating take-or-pay claims would totally escape these costs. Exhibit JER-1A illustrates the inequity by focusing on Tennessee's

four largest pipeline customers—Columbia Gas Transmission Corporation, Consolidated Gas Transmission Corporation, Midwestern Gas Transmission Company and National Fuel Gas Supply Corporation. Their AQLs are as follows:

Columbia	201.3 MMDth
Consolidated	230.4 MMDth
Midwestern	225.0 MMDth
National Fuel	107.9 MMDth
Total	764.6 MMDth

These four pipelines purchased 56 percent, 61 percent, and 26 percent of their AQLs in 1983, 1984 and 1985, respectively. Their total deficiency below AQLs for these three years was 157 percent (44 percent + 39 percent + 74 percent) or 1200 MMDth. *Id.* at 16. Tennessee's weighted average take-or-pay level under its gas purchase contracts is 82 percent. Ex. JER-2. The four pipelines' total purchase deficiency below 82 percent of AQLs for the years 1983, 1984 and 1985 were 26 percent, 21 percent and 56 percent, respectively, for a combined three-year deficiency of 103 percent or 788 MMDth. Based on an assumed weighted average gas cost of $2.50 per Dth, their deficiencies translate into a potential take-or-pay liability of $1.97 billion. Assuming this liability could be settled for 20 cents on the dollar, their responsibility would be about $400 million for this past period. Ex. JER-1A at 16.

While this example may not be a precise tracing of take-or-pay liabilities to certain customers, it illustrates the order of magnitude of the take-or-pay problem caused by cutbacks of purchases by Tennessee's major multi-supplied customers and markets. And it further points up the need to establish a reasonable allocation mechanism to prevent these customers from escaping take-or-pay costs, while the customers who continue to purchase from Tennessee bear the brunt of these amounts as they would certainly do under commodity charge treatment.

Are, then, Tennessee's specific proposals fair and reasonable mechanisms for recovery of prudently incurred take-or-pay costs? In the first place, it is important to bear in mind that producers affiliated with Tennessee are barred from participiptaion in the program, even though take-or-pay exposure to affiliates amounts to over $1 billion. Secondly, only payments actually made will qualify for sharing with customers who will be free to challenge any such payments as imprudently made. Thirdly, each of the proposed tariff articles will only be in effect for a limited time period, *e.g.*, 42 months for Article XXX. Lastly, Article XXXII limits Tennessee's recovery of contract reformation costs to $200 million annually. The absence of some of these limitations led Judge Benkin to find Transwestern's take-or-pay proposals inadequate. 39 FERC at pp. 65,126-31. The presence of these restraints on Tennessee's activities will have the commendable effect of inducing the pipeline to resolve its problems efficiently and expeditiously.

Turning next to the specific proposals, we take up Article XXX first, which covers past take-or-pay costs. Tennessee says it crafted Article XXX as well as the other two articles to achieve a fair balance reflective of the diverse characteristics of its more than 100 sales customers and the customers' benefits from and responsibility for take-or-pay and contract reformation costs. Thus, Article XXX provides for allocating one-third of the past take-or-pay costs on the basis of each customer's AQL for the period January 1, 1981 through December 31, 1985 as compared to the total of all customers' AQL's for that period. One-third of the costs will be allocated on the basis of a customer's purchase deficiency below 82 percent of its AQL for the period January 1, 1981 through December 31, 1985 as compared to all customers' purchase deficiencies below 82 percent for that period. And one-third of the costs will be allocated on the basis of each customer's historical purchase deficiency as compared to the total of all customers' historical purchase deficiencies.

Historical purchase deficiency is the quantity by which a customer's average day purchases for the period January 1, 1983 through December 31, 1985 are less than its average day purchases for the January 1, 1981 through December 31, 1982 period.

It is difficult, if not impossible, to trace directly a particular take-or-pay obligation to a particular customer as the cause of incurring that obligation. However, it is apparent that a decline in a customer's purchases from Tennessee translates directly to a decline in Tennessee's ability to meet its purchase obligations. The three-part allocation takes these factors into consideration while simultaneously providing for a reasonably gradual transition commodity rate approach of recovery to the direct billing approach as Tennessee here proposes. Under the traditional approach to take-or-pay cost recovery, all of Tennessee's sales customers could have expected to be assessed some amount of those costs through the commodity rate. Although Tennessee is now moving to a direct recovery approach predicated on assignment of costs to those customers responsible by reason of purchase deficiencies, Tennessee recognizes that there should be some transition accommodation. For this reason, one-third of the take-or-pay costs are allocated to all customers on the basis of each customer's AQL. The one-third allocation on the basis of purchase deficiencies belowe 82 percent of a customer's AQL is in recognition of the fact that the weighted average take-or-pay threshold in Tennessee's gas purchase contracts is 82 percent. Purchases below this level by Tennessee's customers translate directly into take-or-pay obligations for Tennessee. The last one-third allocation on the basis of a customer's historical purchase deficiencies is in recognition of the customer demand on Tennessee's system during the period in which Tennessee entered into the majority of the gas purchase contracts under which it has incurred take-or-pay obligations. The customer demand experienced by Tennessee during the 1981-1982 period and customer projections of

future increased demand prompted Tennessee to undertake the take-or-pay obligations of gas contracts executed to ensure that the pipeline would be able to serve the customer's gas supply needs.

In sum, the method of allocation of funding amounts among customers strikes what is found to be a reasonable balance between the need to track customer responsibility for take-or-pay and the need for a reasonably smooth transition from pure commodity rate treatment.

It is only Tennessee's Rate Schedule CD customers who will be subject to funding liability under Article XXXI. This is so because it is the Rate Schedule CD customers who have the ability to determine how great or how small the take-or-pay costs will be on the Tennessee system. Under open-access conditions the Rate Schedule D customers will have the opportunity to receive transportation service and thus satisfy their gas requirements from a vastly wider range of suppliers. The Rate Schedules G and GS customers, on the other hand, are essentially precluded by the terms of those rate schedules from purchasing gas supplies from sources other than Tennessee. However, if the Rate Schedule G and GS customers choose to take advantage of the open-access transportation available on the Tennessee system and can therefore choose among suppliers, they will become subject to the funding liability under Article XXXI.

Article XXXII apportions 80 percent of Tennessee's non-affiliate contract reformation costs among all sales customers based on each customer's AQL. Tennessee will determine its contract reformation costs each November 1 and collect the costs from the customers in twelve equal monthly installments commencing the next January. Tennessee's recovery in each year, however, will be capped at $200 million. The article will be in effect for 54 months.

It is obvious that Tennessee has worked hard to come up with just and reasonable mechanisms to fund its take-or-pay obligations. The problem to be solved here is not

whether these are the only mechanisms or even the best mechanisms. Are they just and reasonable mechanisms? I conclude that they are. Article XXX funding is based on the historical fact that Tennessee's take-or-pay exposure is primarily caused by deficiencies in its purchases from producers. These deficiencies are a direct function of Tennessee's customers' deficiencies in purchases from Tennessee. As to Article XXXI concerning future take-or-pay costs, it serves several functions: (1) To allocate future take-or-pay costs among Tennessee's customers in an equitable manner; (2) to afford the customers increased flexibility to purchase gas from other sources; (3) to provide Tennessee with additional incentives to renegotiate its gas purchase contracts and reduce its weighted average take-or-pay level; and (4) to provide the customers with advance notice of the true cost of their decision to purchase from Tennessee or another supplier. Inasmuch as the primary causes of take-or-pay are customer purchase deficiencies, and the transition from commodity rate treatment to deficiency allocation will be accomplished under Article XXX, Article XXXI would determine each customer's responsibility for future take-or-pay costs based strictly on customer purchase deficiencies below specified declining purchase benchmarks. In effect, this represents Tennessee's cost of maintaining the gas supply inventory for the customer's benefit when the customer purchases elsewhere. Article XXXI not only provides for an equitable allocation of future take-or-pay costs among customers—by ensuring that no customer pays for the cost of the supply inventory maintained for another—but also gives Tennessee a strong incentive to renegotiate its gas purchase contracts and reduce its weighted average take-or-pay level. Because the deficiency benchmarks decline to 50 percent over a 3½-year period, Tennessee's customers will be able to reduce their takes from Tennessee without incurring take-or-pay funding exposure under Article XXXI.

In addition, the purchase deficiency benchmarks are pegged to each customer's future AQL, which will reflect any contract demand and AQL reductions or conversions that the customer exercises pursuant to Order No. 436 and Section 284.10 of the Commission's regulations. This gives the customers added flexibility to purchase gas from other sources without incurring take-or-pay liability under Article XXXI. At the same time, however, each customer will retain its firm entitlement to purchase its contract demand and AQL from Tennessee. The increased flexibility afforded the customers by Article XXXI leaves Tennessee with a forceful incentive to renegotiate its gas purchase contracts and reduce its take-or-pay levels because Tennessee will only be able to collect take-or-pay costs attributabel to customer purchase deficiencies below the declining benchmarks. Thus, Tennessee will be assuming the risk for take-or-pay caused by purchase deficiencies below the present 82 percent weighted average level under Tennessee's contracts.

Article XXXII allocates contract reformation costs among Tennessee's customers based on their AQLs. All of Tennessee's customers benefit from the reformation of Tennessee's contracts, whether the reformations involve reductions in future take-or-pay levels or buy-downs of future prices. Even if the customer does not purchase his full entitlement in the future, any reduction in Tennessee's future take-or-pay levels will afford the customer added flexibility to purchase from other sources without being exposed to take-or-pay liabilities from Tennessee. By the same taken, reductions in Tennessee's future gas prices result in the dual benefit of lower-priced gas available from Tennessee and downward pressure on competitors' prices. Finally, Article XXXII's allocation of contract reformation costs among all customers recognizes that Tennessee's gas purchase contracts were executed in the first instance to meet the requirements of all of the customers. Consequently, all of the customers should share in the burdens of the contract renegotiation process.

While I find the proposed mechanisms just and reasonable, I also find that they should be amended to reflect a 50-50 sharing of the prudently incurred non-affiliated take-or-pay costs rather than the 20-80 percentage proposed by Tennessee whereby Tennessee would absorb 20 percent and the customers 80 percent of these costs. It is, of course, difficult to defend any one such determination as against all others because there is a certain arbitrariness involved in the determination. It is also true that I have found Tennessee's gas purchasing practices to be prudent which under ordinary circumstances should permit recovery of all these costs from Tennessee's customers. Nonetheless, it seems here desirable to adopt the Commission's Policy Statement suggestion that the burdens of a take-or-pay solution fall equally upon the pipeline and its customers. Under ordinary circumstances recovery of all costs could be achieved only through commodity charges assessed against future sales, a very chancy prospect for Tennessee when compared with the certain recovery achieved through the direct billing and tracking mechanisms allowed here. So I would amend Tennessee's proposal of a 20-80 sharing to a 50-50 sharing of these burdens. This is not to say that a 20-80 proposal is ungenerous or unsupportable. However, as Judge Benkin commented in *Transwestern*, ". . . this is an area in which pragmatic adjustments are required, theoretical soundness must occasionaly give way to practical considerations . . ." 39 FERC at p. 65,126.

The crisis proportion of the take-or-pay problem requires not only a fair solution but also a prompt solution. Considering the many and diverse causes creating the problem and the uniqueness in the contributions of a myriad of parties to the creation of the problem, it is apparent that a successful and prompt termination of this proceeding will be hastened by requiring Tennessee to assume 50 percent of its non-affiliated, prudently incurred take-or-pay costs.

The Commission's recent proposed Policy Statement includes the following:

> . . . The Commission believes a 50-50 cost sharing approach is equitable based on the nature, extent and causes of the take-or-pay problem. It seems clear that for purposes of establishing a general policy, neither pipelines nor their customers should be required to shoulder the entire burden associated with take-or-pay buy-out and buy-down costs. The Commission likewise believes that no reasonable or adequate basis exists to establish a cost sharing formula of general applicability that would assign a proportionately greated share of those costs to either pipelines or their customers. Accordingly, as a matter of judgment, the Commission finds that the equal sharing approach is reasonable in relation to the overall objective of providing for a fair and equitable apportionment of costs.

38 FERC at p.61,727.

Additionally, as we have already seen, in *Transco* the Commission approved a contested settlement provision that provided for a 50-50 sharing of take-or-pay buy-out and buy-down costs between Transco and its customers. The Commission found that:

> As we have discussed above, we believe that the fact that Transco shares at least 50 percent of the buyout costs (and is responsible for any costs expended over and above the cap) provides assurance that Transco will drive the best bargain possible. We believe this equal-sharing approach provides sufficient incentive to Transco to keep its costs of renegotiation as low as possible and to bargain for competitively priced gas as part of those renegotiations.

38 FERC at p. 61,482.

There is a caveat which, however, must be applied to the 50-50 sharing amendment, *viz.*, it shall only apply to

consenting parties. If a customer decides to challenge the take-or-pay buy-out or contract reformation charge, then the 50-50 provision will be considered waived or cancelled and that customer's challenge will be determined on the merits of his case. In such situation there will be no percentages applicable to these costs which will either be absorbed entirely by Tennessee if imprudently incurred or passed on entirely to the customer if Tennessee's actions were prudent. This caveat is important for two reasons. First, it is fair to Tennessee which, on this record, has shown its take-or-pay liabilities to have been reasonably incurred but which would be faced with automatic challenges to its efforts to pass the buy-out and reformation costs on to its customers at a prudence hearing. In other words, it is a "tails you win, heads I lose" situation for Tennessee if customers can both take advantage of 50-50 sharing and also contest the prudence of the charge.

Second, it will encourage customers to accept a 50-50 sharing of the costs on the basis that 50 percent thereof will not be passed on to them even if those costs were prudently incurred. Moreover, if they do not accept 50-50 sharing, these customers run the risk of being charged with 100 percent of the costs if found to have been prudently incurred. The 50-50 sharing amendment with the caveat here proposed should encourage prompt resolution of Tennessee's take-or-pay liabilities for the benefit of all concerned, a premise which I trust will not be considered "utterly Panglossian." *See Associated Gas Distributors v. FERC*, No. 85-1811, *et al.*, slip op. at 95 (D.C. Cir. June 23, 1987).

The last cited case remands the Order No. 436 proceeding to the Commission with directions to consider, among other matters, the advisability of taking direct action under Section 5 of the Natural Gas Act on the uneconomic contracts now outstanding between the pipelines and their producers. Associated Gas Distributors (AGD) and others have urged that this subject be ad-

dressed in the instant case and the parties have listed it as an issue to be determined herein. Nonetheless, I consider it inadvisable to do so at this time. This is true because the Commission must now under the Court's mandate reassess its findings with respect to Order No. 436. What will be the outcome of such reassessment is, of course, now unknown. Further, it seems here desirable to dispose of Tennessee's proposals as they are put forward in Articles XXX, XXXI, and XXXII without complicating the proceeding with a determination of whether its contracts with producers have become unreasonable because of changed circumstances. In other words, the main issue here concerns Tennessee's tariff proposals and not the reasonableness of its producer contracts which, it seems to me, is a subject peripheral to the main issue and best resolved in a separate proceeding devoted to that subject alone. The Commission, in my opinion, will be well advised to decide Tennessee's proposals now and leave to a later time consideration of the pipeline-producer contract problem. Under its present proposals, Tennessee may be able to renegotiate its problem contracts in such a way as to satisfy those, such as AGD, who believe that these contracts are incompatible with today's market conditions. Tennessee should be given that opportunity. If those efforts end in failure, Tennessee or another complainant may then bring into litigation those contracts which remain allegdly unjust and unreasonable.

VI. Objections to Tennessee's Proposal

Some intervenors, *e.g.*, Northern Illinois Gas Company (NI-Gas), argue that Tennessee's proposals are illogical since they are based on Tennessee's exposure to take-or-pay liability rather than on the basis of any duty owing to Tennessee by its customers. And these customers, of course, had no obligation to buy from Tennessee whatever volumes of gas it contracted to buy from producers. Under these circumstances, NI-Gas says the appropriate method of recovering take-or-pay costs is through a

charge against all users of Tennessee's system on a volumertric basis, i.e., through a commodity charge.

Unfortunately, however, this argument ignores the take-or-pay crises now engulfing Tennessee and other pipeline companies. By advocating a volumetric or commodity charge mechanism, NI-Gas would simply prolong the crisis for Tennessee and, indeed, intensify it because the additional charge, as we have seen, can be expected to drive many customers off the system. Further, one of the basic tenets of cost allocation in the past has been that cost responsibility should follow cost causality. While the bulk of costs varies directly with the amount of gas sold, take-or-pay costs increase with a decrease in gas purchases, that is, as customer purchases decrease, take-or-pay costs increase. Tennesseee's rate design here seeks to place responsibility for cost recovery, at least in part, upon those who have caused the costs to be incurred in the first place. This seems to be a desirable result, one that appears to be a just and reasonable solution to a difficult and complex problem. To repeat, this is not to say it is the only or the best solution, but a just and reasonable one.

There is another factor which I eelieve is ignored by NI-Gas, Staff and others. That is the temporary nature of the new tariff entries. Article XXX expires in 42 months. Article XXXI remains in effect for 49 months and XXXII for 54 months. Thus, the proposals here are of comparatively short duration and are, in effect, a one-time departure from normal practice, a temporary, albeit radical, effort to bring Tennessee back into financial well-being, relieved of at least some of the overwhelming burden of unexpected take-or-pay responsibilities.

Consolidated and some others recommend that Tennessee's past take-or-pay costs be allocated based on certain billing determinants and recovered in Teneseee's corresponding demand rates. Conceptually, demand treatment is really another form of direct billing in that

each customer would be allocated a fixed percentage of Tennessee's costs and could not escape those costs by changing its purchase pattern, as it could under commodity rate treatment. The only differences are (1) the percentages allocated to each customer would be different than under Tennessee's proposal and (2) the costs would be rolled into Tennesee's demand rates and billed as a unit charge each month. On the positive side, because demand treatment is a form of direct billing, it would carry all of the advantages of direct billing with respect to competition, price signals, and preventing nonpurchasers from escaping Tennessee's prudently incurred take-or-pay and contract reformation costs. The drawback of demand treatment is that it does not adequately recognize the principal cause of take-or-pay—customer purchase deficiencies. Tennessee's direct billing proposal would allocate take-or-pay costs more equitably by according greater weight to customer purchase deficiencies, the primary cause of take-or-pay.

Of course, a great number of other objections both in principle and in methodology are raised by the parties in this proceeding. It seems unnecessary to review each and every one of these objections, many of which overlap or have been answered in the findings already made herein. Nonetheless, it seems desirable to comment on the following:

Peoples Gas Light and Coke Company (Peoples) proposes that the prudence review of take-or-pay costs be undertaken before Tennessee is allowed to recover these costs. This, however, would effectively and inappropriately increase the percentage of prudently incurred costs absorbed by Tennessee. On the other hand, Tennessee's proposal, as here modified, would prevent this undue increase in Tennesee's absorption of costs, while affording the non-consenting customers full prudence reviews of all of Tennessese costs and refund protection with interest in the same manner as in a Section 4 general rate case.

New England and others argue that Article XXXI is tantamount to a minimum bill and would discourage customers from purchasing cheaper gas from third-party suppliers rather than from Tennessee. Witness Ramsey distinguished Article XXXI from minimum bills, however.

> The principal distinction is that Article XXXI is dedesigned solely to recover take-or-pay costs, whereas minimum bills, before Order No. 380, reflected all gas and variable commodity costs. One of the Commission's major concerns was that minimum bills recovered gas costs and other costs that were not incurred by pipelines when they did not make sales. In contrast, Article XXXI recovers only the take-or-pay costs actually incurred by Tennessee as a result of each customer's purchase deficiency.

Ex. JER-8 at 72.

The critical difference discussed by Ramsey is consistent with the Commission's own reasoning in Order No. 380. In response to the pipelines' argument that minimum bills helped alleviate take-or-pay, the Commission found that minimum bills were not designed to recover take-or-pay costs and, in fact, would result in an overrecovery of costs by the pipelines. Article XXXI, in contrast, is designed solely to recover Tennessee's actual take-or-pay costs. The parties raising the minimum bill objection are contending, in effect, that any tariff provision, such as Article XXXI, that imposes on the customer a current charge based on purchase deficiencies, rather than on purchases, is an unlawful minimum bill. If the Commission intended to reach that conclusion, it would have done so in Order No. 380 and would not have left the door open for pipelines and Staff to devise novel approaches for apportioning take-or-pay costs. A procedure like that in Article XXXI, which lets the customer know immediately the take-or-pay consequences of his purchase decisions, is one way to send the customers accurate price

signals at the time they make purchase decisions. Without this provision, Tennessee and its customers would continue to be subject to after-the-fact allocations of take-or-pay costs and continued complaints of lack of notice.

Some parties assert that direct billing of take-or-pay costs constitutes "retroactive ratemaking" However, Tennessee is not proposing to recover costs that could or should have been reflected in Tennessee's rates in the past. Indeed, the costs that are recoverable under Tennesse's direct billing proposal are the same costs that would be recoverable under commodity rate treatment. Under the opponents' retroactive ratemaking theory, numerous other cost recovery procedures approved by the Commission would have to be outlawed as retroactive ratemaking. These include the direct billing of retrotive Order No. 94 production-related cost payments and rate refunds which are not known until years later after litigation is completed and rates become final. Focusing on the Tennessee system, witness Ramsey explained that customer's past purchases during Tennessee's three-day peak have traditionally been used to allocate transmission capacity costs among classes of customers and zones and that the G customers' past purchases determine their future billing demand to which Tennessee's demand rate is applied.

Certain parties, including Baltimore Gas and Columbia argue that direct billing, particularly Tennessee's proposed Article XXXI for future take-or-pay costs, is anticompetitive because it allegedly restricts a customer's ability to take advantage of alternative sources of gas. The fatal defect common to all of these parties' analyses, however, is the implication that competition is the only factor to be considered in designing an appropriate cost recovery device. As the Commission and the courts have stressed, enhancing competition must be balanced with the equally important goals of equitably allocating costs and affording Tennessee a reasonable opportunity to re-

cover prudently incurred costs, even when markets turn sour.

Considering the options available to customers under Order No. 436, it seems impossible for Tennessee to restrain competition. Tennessee's customers, not Tennessee, are in full control of their gas supply portfolios and attendant costs. The customers can rely on Tennessee as a firm supplier, arrange for their own firm supplies directly from producers and use Tennessee as a firm or interruptible transporter, purchase spot market gas and use Tennessee as a firm or interruptible transporter, or use any combination of these arrangements. The customers would be able to purchase whatever supply they desired. They would simply have to reflect in their purchase decisions (1) the price of the gas from Tennessee versus the price of gas from alternative suppliers and (2) any take-or-pay costs attributable to Tennessee's firm supplies. Contrary to the opponents' arguments, this is not improper. It merely requires the customers to weigh the costs and benefits of firm, long-term suppies against those of spot gas or other less secure alternatives. The customers can choose either. But they cannot have firm gas without paying the take-or-pay costs that their pipeline supplier incure to ensure that the supply is, in fact, firm. Avoidance of this cost responsibility is what Judge Zimmet rejected in *ANR Pipeline Co.*, when he concluded that a sales customer "should . . . not be allowed to walk away scot-free from the take-or-pay costs reasonably incurred by ANR on its behalf." 38 FERC at p. 65,286. Judge Zimmet also said:

> In its role as a seller, ANR has a duty to its "firm" sales customers such as Mich Con and MGU to maintain an adequate and reliable gas supply to satisfy the customers' long-term needs. When these sales customers are able at time to purchase cheaper gas from others, and need ANR, the very pipeline from which they otherwise buy gas, to transport the

cheaper gas to them (thus becoming with regard to that gas "transportation" rather than "sales" customers of the pipeline), the duty of the pipeline to maintain a long-term supply of gas for them still continues.

* * * *

[A]bstract and abstruse talk about competition, with many an accusation directed at the pipelines for alleged obstructive tactics, fails to come to grips with perhaps the most important question of all. Namely, if pipelines like ANR are no longer to have the primary responsibility for long-term gas supply, who is to have this duty and how will the successor(s) do any better job to avoid incurring take-or-pay premiums to assure such a supply.

Id. at pp. 65,279, 65,287.

Staff and others contend that take-or-pay costs should be assessed in a regular Section 4 rate case where all of Tennessee's costs can be assessed and evaluated. Such a contention must be rejected out of hand. To subject Tennessee to a full blown rate case at this late date would be tantamount to denying any take-or-pay cost recovery within a reasonable period of time. Furthermore, the record here contains all the proof necessary to determine the reasonableness of Tennessee's proposal. There is no need to postpone an assessment of the record on take-or-pay costs to some future time. The time is ripe to do so now.

The Tennessee Small General Service Customer Group (SGS Group) argue persuasively that since they, the G and GS Customers, did not cause any of the take-or-pay costs, none of these costs should be extracted from them. In this they have the support of a statement in the proposed Policy Statement wherein the Commission says:

> Most interstate pipelines have small general service (SGS) type rate schedules which establish one-part rates for serving small, full requirements customers such as small municipalities. These customers account for about five percent of pipeline sales on an industry-wide basis. It appears that these customers have in recent years continued by and large to purchase at reasonably steady levels and therefore have not contributed significantly to the take-or-pay problem. Consequently the Commission believes that SGS customers should be exempt from take-or-pay demand surcharges.

38 FERC at p. 61,729.

Nevertheless, I believe that no one class of customers should be relieved of sharing in some take-or-pay costs. As we have already seen, take-or-pay commitments by Tennessee were an essential element in the pipeline's acquisition of gas to meet the future needs of all its firm customers, G and GS customers as well as large customers. Thus, all customers benefitted from the gas supply acquired under these commitments. While most of Tennessee's cost allocation mechanisms are based on deficiencies a one-third portion of Article XXX allocates a charge to all customers in proportion to each customer's AQL, which brings in the G and GS customers. They are also brought in under Article XXXII because they, like all others, will benefit from contract reformation costs. The result of these allocations seems to me to be a fair sharing of take-or-pay costs among all classes of customers, none of which will be exempt but all of which will participate in the solution of the problem, small as that participation may be.

Finally, Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc. and the Public Service Commission of the State of New York argue that Tennessee's proposed take-or-pay cost recovery mechanism should not be approved unless Tennessee

agrees to provide its customers with standby sales service. In effect, they argue that Tennessee's right to a reasonable opportunity to recover costs associated with its existing service shuold be subject to Tennessee's offering of a new service. I agree with Tennessee that this is tantamount to requiring Tennessee to increase its take-or-pay cost exposure and as such is clearly objectionable. We are here trying to reduce take-or-pay exposure, not to find new sources of exposure. Furthermore, if Tennessee accepts the 50-50 sharing of take-or-pay costs as here proposed, the pipeline will be doing at least its fair share in solving the problem. It should not be asked to do more.

VII. Answers to Commission's Questions

As set forth at the outset of this decision, the hearing order in the instant proceeding contains a series of questions to be answered based on the record developed in the case. These are the identical questions asked in *Transwestern* which Judge Benkin answers at 39 FERC at pp. 65,131-32. The Tennessee record supports the following answers assuming that the Commission equates "tracking" with "direct billing":

> 1. Would Tennessee's having a tracking treatment for purchase gas costs without having a comparable tracking treatment for take-or-pay and buy-out costs skew Tennessee's incentives to contract appropriately such that a truly least-cost supply is not achieved?
>
> A. Tennessee should be able to track its purchase gas costs, its take-or-pay buy-out costs and its contract reformation costs. The incentives to achieve a truly least-cost supply of gas will come from established efforts to reduce takes, renegotiate contracts, buy-out contracts and continue a least-cost purchase program, all of which are in place at Tennessee today and have been for some time.

2. If Tennessee had trackers for both gas purchases and take-or-pay costs, would these "trackers" cause Tennessee's management to devote too few resources to minimizing of gas costs?

A. I do not believe so. The sharing of these take-or-pay costs with its customers as here proposed will be a strong incentive for Tennessee to bargain hard.

3. Should Tennessee develop a separate service for those customers who wish "backup" or "peaking" supplies as an addition to the traditional service of providing base load supplies?

A. No. This will simply expose Tennessee to more take-or-pay costs.

4. Must take-or-pay buy-out costs be billed as part of Tennessee's total gas supply costs in the commodity cost component of its rates for accurate price signals to be observed?

A. No. To bill take-or-pay buy-out costs in the commodity cost component is tantamount to requiring Tennessee and/or its captive customers to absorb these costs. Is also would enable the customers who are largely responsible for the incurrence of the costs to escape from sharing in their payment. Such treatment must result in distorted price signals.

5. Is reliance upon the commodity charge to reflect all costs of gas supply an appropriate basis for the allocation of the risk of gas acquisition costs among Tennessee and its various customer classes?

A. Reliance upon commodity charge treatment for allocating take-or-pay buy-out and contract reformation costs will place the burden of these costs on full requirements or captive customers and permit others to escape from payment of these costs. Such allocation would be disastrous to full requirements customers as well as to the pipeline.

VIII. Conclusion

It follows that subject to review by the Commission on exceptions or upon the Commission's own motion, *it is ordered* that:

1. Tennessee's gas purchasing, contracting, acquisition and supply management practices are found to have been prudent and reasonable; and

2. Tennessee's direct billing tariff mechanisms and provisions are approved subject to Tennessee's acceptance of 50-50 sharing of take-or-pay buy-out and contract reformation costs and as modified to provide for prudence reviews of such costs only by parties who do not consent to 50-50 sharing as herein provided.

APPENDIX E

FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. RP86-119-000, TA84-2-9-007
and TA85-1-9-004

TENNESSEE GAS PIPELINE COMPANY,
a Division of Tenneco Inc.

ORDER APPROVING CONTESTED OFFER OF SETTLEMENT WITH MODIFICATIONS

(Issued February 8, 1988)

Before Commissioners: Martha O. Hesse, Chairman; Anthony G. Sousa, Charles G. Stalon, Charles A. Trabandt and C. M. Naeve.

I. Introduction

Before the Commission for review is an offer of settlement filed October 14, 1987, by Tennessee Gas Pipeline Company (Tennessee) to resolve certain issues in the above-captionad dockets and to establish procedures to recover certain take-or-pay costs. In filing its proposal, Tennessee stated its belief that the settlement offer is in general accord with the take-or-pay passthrough policies announced in Order No. 500.[1] The settlement is supported by some parties, but it is contested at least in part by many parties. In addition, five other competing settlement proposals were filed. The Commission determines that sub-

---

[1] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, *FERC Statutes and Regulations* ¶ 30,761 (1987) (Interim Rule and Statement of Policy, Docket No. RM87-34-000). These interim regulations became effective on September 15, 1987.

ject to the modifications, conditions, and clarifications in this order, the offer of settlement filing by Tennessee on October 14, 1987 is approved.

II. Procedural Background

On June 3, 1986, Tennessee filed certain revised tariff sheets to implement rates, terms and conditions of service under which it would implement open access transportation under Part 284 of the regulations [2] for new and grandfathered transportation services. Additionally, and interrelated to that filing, Tennessee proposed Articles XXX, XXI, and XXXII which would permit Tennessee to directly bill 80 percent of the costs related to (1) recoupable and nonrecoupable past and future take-or-pay payments made to non-affiliated suppliers and (2) lump sum payments made to non-affiliated suppliers in consideration

[2] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, *FERC Statutes and Regulations, Regulations Preambles 1982-1985* ¶ 30,665 (1985), *modified,* Order No. 436-A, *FERC Statutes and Regulations, Regulations Preambles 1982-1985* ¶ 30,675 (1985), *modified further,* Order No. 436-B, *FERC Statutes and Regulations* ¶ 30,688 (1986), *reh'g denied,* Order No. 436-C, 34 FERC ¶ 61,404 (1986), *reh'g denied,* Order No. 436-D, 34 FERC ¶ 61,405 (1986), *reconsideration denied,* Order No. 436-E, 34 FERC ¶ 61,403 (1986), *vacated and remanded sub nom. Associated Gas Distributors v. FERC,* No. 85-1811 (D.C. Cir., June 23, 1987) (*AGD*). In *AGD* the court generally upheld the substance of Order No. 436 and the procedures employed in adopting it, but found problems with certain issues and vacated and remanded the matter for further proceedings. On August 7, 1987, the Commission issued Order No. 500, which promulgated interim regulations in response to the court's remand. *FERC Statutes and Regulations* ¶ 30,761 (1987). That order was modified in Order No. 500-A, *FERC Statutes and Regulations* ¶ 30,772 (1987) and Order No. 500-B, *FERC Statutes and Regulations* ¶ 30,770 (1987). The Order No. 500 regulations generally became effective on September 15, 1987, although, pursuant to Order No. 500-B, the effective date of take-or-pay crediting and CD conversion provisions is January 1, 1988. (Citations will hereinafter reference Order No. 436, *et seq.* and Order No. 500, as appropriate, together with the page in the relevant volume of *FERC Statutes and Regulations*).

for modifications to pricing or take-or-pay provisions included in Tennessee's gas purchase contracts. Tennessee proposed to absorb the remaining 20 percent of non-affiliate take-or-pay costs plus all affiliate take-or-pay costs.

On July 2, 1986, the Commission issued an order which, among other things, rejected Tennessee's take-or-pay proposal (36 FERC ¶ 61,032 (1986)). Nevertheless, the Commission set the matter for hearing to allow Tennessee an opportunity to support its proposal. Voluminous evidence was submitted by numerous witnesses on behalf of Tennessee, the staff and a large number of parties. The hearing began on December 9, 1986, and concluded on January 16, 1987.

Following the submission of initial and reply briefs, the administrative law judge issued his initial decision on July 9, 1987 [40 FERC ¶ 63,008]. The judge concluded that Tennessee's gas purchasing, contracting, acquisition and supply management practices were prudent and reasonable. The judge also found that Tennessee should be authorized to directly bill its non-affiliate take-or-pay costs, but determined that Tennessee should absorb 50 percent (rather than 20 percent) of such costs as well as all affiliate take-or-pay costs. Briefs on exceptions and briefs opposing exceptions were filed on August 10, 1987, and September 8, 1987, respectively.

Docket Nos. TA84-2-9-007 and TA85-1-9-004 involve Tennessee PGA filings to be effective July 1, 1984 and January 1, 1985, respectively. In its order issued March 10, 1987 in these two proceedings (38 FERC ¶ 61,236 (1987)), the Commission specifically banned relitigation of issues raised in Docket No. RP86-119-000 (38 FERC ¶ 61,236, at p. 61,752). On October 16, 1987, an initial decision was issued in these two PGA dockets [41 FERC ¶ 63,006]. The administrative law judge granted Tennessee's motion for summary disposition, terminating these proceedings. The judge agreed with Tennessee that the

language in the hearing order was an absolute bar to relitigation of the issues in RP86-119-000, and that in fact there were no other issues left to be decided.

The settlement proposal filed by Tennessee would, if approved, resolve all issues in Docket No. RP86-119-000. Additionally, Tennessee maintains that its settlement proposal would resolve outstanding purchasing practices issues in Docket Nos. TA84-2-9-007 and TA85-1-9-004.

III. Description of the Settlement

Tennessee's Stipulation and Agreement provides for a 50-50 sharing between Tennessee and its customers of all take-or-pay costs (affiliate and non-affiliate) that Tennessee incurs through December 31, 1989. Take-or-pay costs are defined as (1) non-recoupable payments to buy out of take-or-pay liability or to reform existing contracts and (2) the cost-of-service effect of recoupable take-or-pay payments (prepayments). The customers' share is limited by a total cap of $750 million, which includes a separate cap of $100 million applicable to affiliate take-or-pay costs.

The customers' 50 percent share of the take-or-pay costs would be directly billed and recovered through a fixed take-or-pay surcharge. Tennessee estimates that two-thirds of its take-or-pay costs will be contract reformation costs i.e., costs to prospectively modify the price, take-or-pay provisions, or other economic terms of its gas purchase contracts. It estimates that one-third will be a combination of payments to buy out accrued take-or-pay liabilities and the cost-of-service effect (return and related income taxes) of prepayments. Accordingly, each customer's take-or-pay surcharge is based on an allocated percentage based on two separate allocation mechanisms. The first allocation mechanism, which addresses settlement costs of take-or-pay claims, applies only to Rate Schedule CD customers and is based on an equal weighting of the customers' (1) average annual quantity limitation for the period 1981-85, (2) deficiencies in purchases

during 1981-85 below 82 percent of the customer's annual quantity limitation in the same period, and (3) deficiencies in purchases during 1983-1985 as compared to purchases in 1981-82. The second allocation mechanism, which addresses contract reformation costs, applies to Rate Schedule CD, G, and GS customers and is based on each customer's annual quantity limitation as of January 1, 1986. The first and second allocation methodologies are accorded a 1/3 and 2/3 weighting, respectively. The consolidation of these two allocations results in the percentages to be billed each customer.

Of the $750 million that may be recovered from Tennessee's customers under the settlement agreement, Tennessee has assumed that one-third or $250 million is for buyout costs and two-thirds or $500 million is for buydown costs. Thus, in the proposed offer of settlement, one-third of the customers' charge is based on the first allocation mechanism and two-thirds is based on the second allocation mechanism. As noted, the G and GS customers are excluded from the first allocation mechansm and, therefore, in effect are assigned no responsibility for take-or-pay buyout costs.

The stipulation also provides for continued negotiations with respect to the development of a gas inventory charge, for continued pursuit by Tennessee of modifications of the terms of Tennessee's gas purchase contracts by exercise of the Commission's authority under section 5 of the Natural Gas Act (NGA) and for establishment of a new standby sales service for Tennessee's Rate Schedules CD, G and GS customers electing to convert to firm transportation.

Finally, the settlement would, with certain limitations, preclude any further challenge by any party or the Commission staff regarding (1) the take-or-pay costs subject to recovery under the settlement, (2) Tennessee's gas purchasing, contracting, contract reformation, acquisition and supply management practices prior to the effective date of the settlement, and (3) Tennessee's existing gas

purchase contracts and costs thereunder. Further, all rates and charges billed under the settlement provisions would be deemed just and reasonable for purposes of sections 4 and 5 of the NGA and would be eligible for recovery by any customer subject to FERC rate jurisdiction without further challenge by any party or staff.

IV. Competing Settlement Proposals

Tennessee's settlement filing generated five alternative proposals. These other filings, by certain customer groups, parallel the Tennessee proposal in many respects. The primary distinctions are that they would alter the cost allocation formula proposed by Tennessee.

A. The Customer Group Proposal

The first competing proposal was filed jointly on October 30, 1987, by Consolidated Edison Company of New York, Inc., The Brooklyn Union Gas Company, Long Island Lighting Company and Public Service Electric and Gas Company (Customer Group). This proposal provides for a 50-50 sharing between Tennessee and its Rate Schedule CD, G and GS customers of all costs Tennessee has incurred to resolve take-or-pay claims or reform the economic terms of its gas purchase contracts with non-affiliated producer-suppliers. In addition, it includes costs that may be incurred prior to January 1, 1990, to resolve take-or-pay liabilities now accrued under those contracts. Recovery of these costs from Tennessee's sales customers is limited at this time to a total amount of $357.5 million. The customers' 50 percent share of the costs incurred is to be recovered by a fixed take-or-pay surcharge. The percentages due from each customer are derived by two separate allocation mechanisms.

One allocation is based on the customer's contract entitlement and is applied to half of the customers' share of amounts paid by Tennessee to non-affiliated producer suppliers as of the date of the settlement, up to a maximum

of $57.5 million. The other allocation is based on the customer's purchase deficiency in the 1981-1986 period. It is applied (a) to the other half, up to a maximum of $57.5 million, of customers' share of amounts paid by Tennessee to non-affiliates as of the date of the settlement, and (b) to the customers' share up to a maximum of $242.5 million, of amounts that may be paid by Tennessee after the date of the settlement, but before January 1, 1990, to resolve take-or-pay liabilities or claims that had accrued as of the date of the settlement.

The cap on the amount of recoverable take-or-pay costs is reduced to eliminate affiliate payments, carrying charges on prepayments and also to eliminate the costs estimated to be incurred through contract reformation. Proponents of the customer group proposal argue that recovery of contract reformation costs should be deferred until after the Commission has had an opportunity to rule on contract reformation in a section 5 context. Under Article 1, section 6 of the Customer Group proposal, Tennessee would be allowed to recover an additional $242.5 million in the event the Commission denied contract reformation relief under section 5 of the NGA and that decision is affirmed on judicial review.

An additional item contained only in the Customer Group proposal would eliminate current Tennessee restraints on the injection of third party gas into SS-E and SS-NE storage.

B. The SGS Proposal

A second competing propòsal was filed jontly on November 7, 1987, by the Tennessee Small General Service Customer Group, the Cities of Clarksville, Springfield and Portland, Tennessee, Humphreys County Utility District, Tennessee, and Western Kentucky Gas Company (SGS proposal). This settlement offer provides for the allocation of take-or-pay liability among Tennessee's customers solely on a purchase deficiency basis. A deficiency volume

is calculated for each customer whose average annual purchases from Tennessee during the years 1983-1986 were less than the customer's average annual purchases from Tennessee during the years 1981-1982. All such deficiency volumes are summed and each customer's percentage share of the total is calculated. Similar to the Tennessee proposal, recovery is allowed up to $750 million, and this includes affiliate payments up to $100 million.

C. The New England Proposal

Another competing settlement proposal was filed by the New England Customer Group (New England) on November 9, 1987. Under this proposal, Tennessee may recover 50 percent of its non-affiliate take-or-pay costs incurred no later than December 31, 1988, under gas purchase contracts in effect on or before December 31, 1987. Recovery is capped at $216.7 million. The fixed take-or-pay charge is based on each customer's cumulative purchase deficiency, using 1981 as the base year and 1982-1986 as the comparison years.

As with the Customer Group proposal, New England reduces the cap on recoverable take-or-pay costs to eliminate both affiliate payments and costs estimated to be incurred through contract reformation. New England likewise argues that if effective section 5 relief is ordered, there will be no reason for Tennessee to incur buydown costs. In addition, the New England proposal also provides for mandatory contract reformation of Tennessee's take-or-pay contracts under Section 5 of the NGA.

D. The Consolidated Proposal

Two final competing settlement offers were filed on November 16, 1987. A proposal by Consolidated Gas Transmission Corporation (Consolidated) provides for a 50-50 sharing between Tennessee and its Rate Schedule CD, G and GS customers of all costs Tennessee has paid prior to November 1, 1987, to resolve take-or-pay claims

or to reform its gas purchase contracts. Tennessee is to file no earlier than May 31, 1988, tariff sheets to be effective no earlier than July 1, 1988, setting forth each customer's cost liability. The customers' 50 percent share of the costs incurred will be recovered by a fixed take-or-pay surcharge applied to Tennessee's demand rates. The percentages due from each customer are based 50 percent on each customer's contract demand compared to total contract demand of all Tennessee customers and 50 percent on each customer's annual quantity limitations compared to the total AQL of all Tennessee customers.

E. The National Fuel Proposal

National Fuel Gas Supply Corporation (National Fuel) submitted a proposal allowing Tennessee to recover 50 percent of its take-or-pay accruals incurred on or before August 14, 1987. Customer share of these costs is not to exceed $300 million. Each customer's allocated percentage is based upon the deficiency of average purchases during 1982-1986 compared with 82 percent of the customer's annual volume limitation in 1981. In the alternative, National Fuel's proposal provides that the Commission may establish a hearing limited to the issue of what is a representative base period for purposes of applying the cumulative purchase deficiency method set forth in Order No. 500. Like New England, the National Fuel proposal provides for mandatory contract reformation.

V. Discussion

A. Preliminary Matter

National Fuel contends that if the Commission does not reject Tennessee's settlement offer, it must at least set the proposal for hearing in order to resolve issues of material fact. These include issues with respect to the total recoverable take-or-pay amount, the prudence of Tennessee's actual payments, and certain aspects of the allocation mechanism.

The Commission disagrees. Reopening the record would serve no useful purpose. The Commission already has before it more than sufficient evidence to permit a thorough analysis of all aspects of the settlement. Accordingly, the request for hearing is denied.

B. Introduction

The extensive hearing record in this case, as well as the number of competing settlement proposals and the lengthy comments filed, indicate that there is no single or perfect answer to the take-or-pay problem. Moreover, the comments and varying proposals demonstrate that the amounts at stake and the diverse interests of Tennessee's customers render this case difficult to settle through an agreement that would be unanimously or broadly supported by the active participants. At the same time, the Commission is committed to the goal of resolving as quickly as possible the question of who should absorb the pipelines' take-or-pay liabilities which is a deterrent to competitive natural gas markets and services. Accordingly, the Commission must now decide the matters on which the participants cannot agree, particularly the issue of how Tennessee' take-or-pay costs should be allocated among its customers.

Unlike other proceedings where the Commission has severed contesting parties from settlements and afforded them a hearing, the hearing in this case has already taken place. There is no basis for severing anyone from the obligations imposed by the Commission's decision on the merits. This is consistent with the statement in Order No. 500 that the Commission would approve contested settlements on the merits if supported by substantial evidence on the record.

In general, the Commission adopts the proposal submitted by Tennessee on October 14, 1987, with certain modifications. Discussed below are the issues raised both by the comments to that proposal and by the competing

settlement offers. The Commission's resolution concludes the discussion of each issue.

C. *Prudence Pending PGA Dockets*

No serious allegation of imprudence has been raised as an obstacle to Commission approval of a settlement proposal in this case. A few parties do object to Article I, Section 9 of the Tennessee proposal which bars litigation of Tennessee's purchasing practices and existing gas purchase contracts, all of which were at issue in the hearing in Docket No. RP86-119-000. Alternatively, staff and others argue that Section 9 is overly broad, at least to the extent that it precludes future challenges to Tennessee's reformed contracts entered into prior to the effective date of the settlement. Staff argues that the record contains no evidence as to these contracts, and it is therefore inappropriate to require parties to forfeit the right to challenge them.

It is the Commission's view that with respect to parties who no longer seek to challenge the prudence of Tennessee's purchasing practices and existing gas purchase contracts, the approval of this settlement, with modification, constitutes settlement of that issue. Only Baltimore Gas & Electric *et al.*,[3] appear to continue to question Tennessee's prudence, however, their position is not entirely clear from their filing.[4] However, consistent with Order No. 500, if these parties wish to continue to litigate the prudence issue, they will be permitted to do so. As stated in Order No. 500, the Commission will, if it appears reasonable and permissible to do so, approve contested settlements as to all consenting parties and initiate separate hearings as to opposing parties. Furthermore, in any

---

[3] Baltimore Gas & Electric filed jointly with Columbia Gas Distribution Companies, Washington Gas Light Company, the Office of the Consumers' Counsel of Ohio, and the Maryland Public Service Commission.

[4] *See* BG&E *et al.*, Initial Comments at p. 3.

cases where hearings are held, the Commission will permit a pipeline the opportunity to recover from litigating parties its proportionate share of all of the pipeline's take-or-pay costs found to be prudent even if the amount allowed is greater than the amounts initially claimed by the pipeline. In this case, there is already a significant record and initial decision on this issue, and the Commission will rely on that record. In light of the above, if BG&E *et al.*, wish to continue to challenge the prudence of Tennessee's purchasing practices and existing gas purchase contracts they must so state in a petition for rehearing of this order.

As noted, however, under the approved settlement proposal, Tennessee will not be subject to any relitigation of its past practices and existing contracts. This bar includes challenges to Tennessee's reformed contracts entered into prior to the effective date of the settlement. Moreover, under the language of Tennessee's proposal, customers would not be allowed to challenge Tennessee's contract reformation efforts, including resolution of take-or-pay claims and the resultant costs sought to be recovered. Since Tennessee will be absorbing 50 percent of the reformation costs, it will have an incentive to bargain seriously as it renegotiates its contracts. Also, as emphasized by Tennessee, the settlement does not limit any party's right to challenge Tennessee's future costs and charges, including gas costs and gas inventory charges, which may be affected by Tennessee's reformed contracts. The costs insulated under the settlement from challenge are the costs actually incurred by Tennessee in reforming the contracts. These are the costs that Tennessee is sharing 50-50 with the customers.

One final matter related to settlement of the prudence of Tennessee's purchasing practices and existing gas purchase contracts must be addressed. New England Customer Group and certain other parties argue that Tennessee's PGA Docket Nos. TA84-2-9-007 and TA85-1-9-004

should not be included in this settlement. They contend that the issues raised in these two proceedings are not identical to those pending before the Commission in Docket No. RP86-119-000.

The Commission disagrees. The issues that could lead to any relief in the PGA dockets, which concern a past period, are subsumed within the issues resolved in the settlement of Tennessee's past purchasing practices. Although the PGA dockets involve gas costs, whereas Docket No. RP86-119-000 involves take-or-pay, both costs arise out of the same contracts and practices. Consistent, however, with the decision discussed above to separate parties who wish to litigate the prudence issue, these PGA docket proceedings would be continued as to those non-consenting parties.

D. Cap on Cost Recovery/Affiliate Costs

The Commission does not completely agree with those parties who contend that Tennessee's $750 million cap on the recovery of take-or-pay costs is too high. The hearing record in this case evidences that Tennessee's proposed cap is well below the level of its take-or-pay liability exposure.[5] Moreover, under the policy statement adopted in Order No. 500, there is no cap on the amount of take-or-pay costs that a pipeline transporting under Part 284 may seek to recover through the fixed take-or-pay charge.

The Commission does agree, however, with those parties opposing Tennessee's proposal for the recovery of up to $100 million of affiliate take-or-pay costs. Thus, Article I, Section 6 of the Tennessee proposal must be eliminated, and the $750 million cap must be adjusted to eliminate the $100 million component for affiliate take-or-pay costs. There is no record support for the level of the $100 million

---

[5] Tennessee's take-or-pay liability exposure exclusive of affiliate take-or-pay, is approximately $3 billion through 1986. *See* Exh. JER-3.

cap. While there may be references to Tennessee's affiliate take-or-pay exposure in the record, this subject was not at issue in the case because Tennessee never proposed to collect affiliate take-or-pay costs. The Commission declined to rule, when adopting Order No. 500, on whether a pipeline may recover take-or-pay costs paid to producer affiliates. The Commission stated its reservations about whether any such costs should be borne by a pipeline's customers. While one can reasonably assume that a pipeline will bargain hard when dealing with non-affiliated producers where the pipeline is required to absorb 50 percent of the costs, no such assumption can be made in the case of affiliated producers.

Tennessee's proposal does include a provision that prior to recovery of any of its affiliate costs, it will submit to all parties and the Staff information sufficient to support recovery of those payments. If any party objects to recovery, the Commission is to establish procedures for examining the comparability of the affiliate payments with those made to third parties.

This comparability standard, however, does not solve the problems underlying recovery of affiliate payments. Moreover, the standard is not administratively feasible. The individual requests for cost recovery would likely generate repeated protests and endless litigation among the parties. In sum, the significant problems presented by Tennessee's proposal to recover affiliate take-or-pay costs warrant rejection of that portion of its settlement proposal.

If Tennessee wants to recover take-or-pay payments paid to an affiliate it should make a separate filing to do so. This will enable the Commission to scrutinize such affiliate payments. In addition, in order to minimize the difficulty inherent in evaluating such affiliate payments the Commission will only permit take-or-pay buy-out and buy-down payments paid to an affiliate to be passed through in the commodity component of the pipeline's sales rates.

In this way the payments will be subject to the check of the market place in addition to Commission scrutiny of the level of the payments.

E. Recovery of Prepayments

Under Article I, Section 1a. of its proposal, Tennessee defines recoverable take-or-pay costs to include the cost of service effect of prepayments which Tennessee has committed on or before December 31, 1989, to pay to satisfy take-or-pay claims under existing gas purchase contracts. Certain parties request the Commission to modify the Tennessee proposal to foreclose the recovery of these carrying costs on prepayments. They note the policy statement adopted in Order No. 500 which provided that the alternative fixed charge passthrough mechanism would be available only for take-or-pay buyout and buydown costs and specifically excluded recovery of take-or-pay prepayments and related carrying costs.

The Commission agrees that Tennessee's proposal should be modified to exclude prepayments. Beginning in April 1985, with the Policy Statement in Docket No. PL85-1-000 [6] and continuing through the proposed policy statement issued in March 1987,[7] and in the policy statement adopted in Order No. 500, the Commission has consistently referred only to take-or-pay buyout and buydown costs.

The Commission policy on buyout and buydown costs has not addressed prepayments because all prepayments are considered as a rate base item. These are amounts spent for which a service will be provided in the future. The Commission's rate treatment of all prepaid items is to include them as part of the rate base, thus earning a rate

---

[6] Statement of Policy and Interpretive Rule, *FERC Statutes and Regulations, Regulations Preambles (1982-1985)* ¶ 30,637 (1985).

[7] Proposed Policy Statement on Recovery of Take-or-Pay Buy-out and Buy-Down Costs by Interstate Natural Gas Pipelines, 38 FERC ¶ 61,230 (1987).

of return and related income taxes. Gas prepayments are treated no differently, and there is no good reason to change this policy.

Excluding prepayments from any special billing and tracking mechanism continues to be appropriate as a matter of policy. A primary reason the Commission has provided pipelines with the opportunity to separately bill buyout and buydown costs is to afford pipelines the opportunity to seek timely and permanent relief from their take-or-pay contracts. The cost of service related to prepayments, however, recurs annually and does nothing to ameliorate underlying contractual problems.

To allow the tracking of Account 165 prepayments is especially inappropriate when, as proposed by Tennessee, the pipeline is allowed to use its overall pre-tax return as the measure of cost of service for this item. In such a case, the pipeline has a financial incentive to make prepayments rather than buyouts and buydowns, because the cost of service recognized for prepayments exceeds their actual cost to the pipeline. For these reasons, the Commission adheres to the existing policy as reflected in the interim rule. Accordingly, the Tennessee proposal will be modified to exclude prepayments.

F. Recovery of Future Costs

Certain parties argue that only known and measurable buyout and buydown costs should be considered in approving any settlement proposal in this case. The Peoples Gas Light and Coke Company (Peoples Gas) cites section 2.104 (c)(1) of the interim regulations which provides that a pipeline may seek to receive buyout and buydown costs actually paid as of the date of the filing or known and measurable within nine months of the filing. In contrast, Tennessee's proposal would track buyout and buydown costs incurred through December 31, 1989.

Peoples Gas proposes that Tennessee be required to either make periodic filings to flow through known and

measurable costs or resolve all of its contract problems by December 31, 1988. It contends that this would give Tennessee an incentive to resolve its take-or-pay liabilities and institute an appropriate inventory holding charge by the December 31, 1988 deadline, since take-or-pay related costs for subsequent periods would be otherwise unrecoverable. In response, Tennessee argues that since it will only be allowed to recover its actual take-or-pay costs, its settlement proposal accomplishes the goal of Order No. 500 through a streamlined process that eliminates the need for nine-month estimates that would ultimately be supplanted with actual costs anyway.

As an alternaitve to enforcing section 2.104(c)(1), the Commission will modify Tennessee's proposal to include a time limit as well as the $650 million cap. In the Commission's view, the alternative passthrough mechanism should be available to Tennessee for recovery of take-or-pay buyout and buydown costs which are the result of negotiations completed by December 31, 1988. Thus, Article I, Section 1.a of the Tennessee proposal is modified to allow recovery of take-or-pay buyout and buydown costs which Tennessee has either paid by December 31, 1988, or by that date incurred a written obligation to pay. In this regard, the Commission notes Tennessee's agreement with staff's clarification of "committed" in Article I, Section 1 as meaning committed in writing, with interest to be calculated from the date of payment. The language of the settlement should be modified to state this clearly.

In addition, language must be included in Tennessee's settlement proposal to make clear that the $650 million cap is an absolute one. As pointed out by staff, the settlement as drafted would allow Tennessee the discretion to reform contracts (or buy out of past take-or-pay liability) after December 31, 1988, with the result that any associated costs would not be subject to the cap (or to the settlement's sharing provision). This is not acceptable.

The $650 million must be an absolute cap on the customers' share of take-or-pay cost, not merely a cap for a specified time period.

G. Tennessee Cost Allocation Proposal

The Commission recognized in Order No. 500 that the causes of pipeline take-or-pay problems are many and complex and include reduced purchases by pipeline customers due to purchases from alternative suppliers, fuel switching by industrial users due to lower fuel oil prices, reduced levels of economic activity, and conservation. Moreover, no one segment of the industry is entirely responsible for the take-or-pay problem. Consequently, as noted above, each segment must assume a portion of the burden of resolving the problem.

Similarly, the selection of an appropriate method of allocating among customers their share of take-or-pay costs must be based both on the customer's contributions to costs incurred, as well as the need for the broadest reasonable sharing of the costs. The Commission in approving an allocation formula must find a balance that fairly apportions costs among all of Tennessee's customers.

Numerous cost allocation methodologies have been suggested in this proceeding. These are contained in the various competing proposals as well as the filed comments. Tennessee believes that its proposed allocation formula, which is similar to that approved by the presiding judge, provides for the most equitable distribution of costs. With respect to the cost allocation issue, the Commission agrees with the statement of the judge in the initial decision in this proceeding that the problem to be solved is not whether Tennessee's is the only valid billing mechanism, but whether it is just and reasonable. The Commission concludes that it is.

Not surprisingly, the allocation of take-or-pay costs is a matter of great concern and controversy among the cus-

tomers. Those who purchased at high load factors or at close to their historical purchase levels argue that they are not responsible for take-or-pay, and that these costs should be allocated strictly or primarily on the basis of purchase deficiencies. Those who substantially cutback their purchses from Tennessee, i.e., were the most "deficient", contend, on the other hand, that take-or-pay costs should not be apportioned based on purchase deficiencies. In their view, such an allocation scheme imposes costs on the basis of historical purchase decisions which were entered into without any notice whatever that those decisions would subsequently form the basis for cost imposition.

In accord with Tennessee's expectation that ⅓ of its take-or-pay costs will relate to buyout payments and ⅔ to contract reformation costs, each customer's surcharge is separately determined based upon the consolidation of two separate allocation mechanisms, weighting these mechanisms on a ⅓-⅔ basis. The one-third weighted take-or-pay buyout allocation formula itself embodies a three-prong procedure that apportions costs among Tennessee's CD customers based on an equal weighting of (1) the customer's annual quantity limitation (AQL), (2) the customer's deficiency in purchases below 82 percent of its AQL during the period January 1, 1981 through December 31, 1985,[8] and (3) the customer's historical purchase deficiency, in this case the amount by which the customer's average day purchases during the years 1983-1985 fell short of its purchases during the years 1981-1982. Tennessee states that the purpose of this three-prong allocation mechanism is to accord substantial weight (⅔) to purchase deficiences, which in Tennessee's view is the primary cause of its take-or-pay liability, while recognizing (through the ⅓ AQL allocation) that Tennessee executed its take-or-pay contracts for the bene-

[8] Tennessee's weighted average take-or-pay level under its gas purchase contracts is 82 percent.

fit of all of its customers. Tennessee states that its proposal excludes the G and GS customers from the one-third weighted take-or-pay buyout allocation formula because these customers were unable to switch from Tennessee to alternate suppliers.

The two-thirds weighted allocation formula, which addresses contract reformation costs, applies to Rate Schedule CD, G, and GS customers and is based on each customer's annual quantity limitation as of January 1, 1986. This formula rests on the premise that all of Tennessee's customers will benefit from the reduced prices and added flexibility resulting from the modification of Tennessee's gas purchase contracts. Thus G and GS customers are included in this allocation mechanism.

In sum, Tennessee's settlement offer allocates take-or-pay costs based partly on past purchase deficiencies and partly on annual entitlement. Although this allocation methodology deviates from Order No. 500, which would allocate all costs based on purchase deficiencies, the settlements allocation factor give recognition to several circumstances that are related to the incurrence of take-or-pay on Tennessee's system and thus do not appear to be unreasonable.

Because Tennessee's proposal would allocate take-or-pay costs at least in part based on past purchase deficiencies, certain parties and customers argue that the proposal is not in accord with the recent Court of Appeals decision in *Columbia Gas Transmission Corp. v. FERC*, No. 85-1846 (D.C. Cir. October 27, 1987). In that case, the court held that certain Commission orders approving the direct billing of NGPA section 110 costs based on past purchases constituted unlawful retroactive ratemaking. The court stated that the effect of the Commission's orders approving the direct billing mechanism would be to require downstream purchasers to pay a surcharge over and above the rates on file at the time of sale for gas they had already purchased. The court noted, however, that, while the prohibition against retroactive ratemaking

might have been overridden through adequate notice that purchasers would be expected to pay the deferred charges at a later date, the Commission had not provided such notice.

The decision in *Columbia* is distinguishable. The direct billing mechanism at issue in that case would have imposed a rate increase for gas already sold. In this proceeding, the Commission is determining an appropriate allocation of current settlement payments. Tennessee's proposal envisions an allocation of those take-or-pay costs in part on the basis of customers' past purchase deficiencies. There is nothing in the proposal which would retroactively change the rates Tennessee has charged its customers in the past or which would involve imposing a rate increase for gas already sold. Indeed, under the new policy adopted in Order No. 500, a pipeline may enter into a settlement and then seek to recover the cost incurred thereunder in rates to be charged in the future. The settlement buyout or buydown costs are a current expense incurred for or in connection with gas service rendered.

As the Commission stated recently when considering the take-or-pay recovery mechanism proposed by Transwestern Pipeline Company,[9] the rate treatment of take-or-pay settlement costs would be much the same as the treatment usually accorded costs incurred in resolving any contract dispute, which would be permitted to be included in the next rate filing. If pipeline recovery of take-or-pay costs at the time they are paid were retroactive ratemaking merely because the costs relate back to some past event, a pipeline could never lawfully recover these costs under *any* rate treatment. Tennessee's proposal does not constitute retroactive ratemaking because it does not seek to recover costs incurred in a prior period. Tennessee seeks approval of a mechanism to provide for the recovery of current costs that it will pay to

---

[9] *Transwestern Pipeline Company*, 40 FERC ¶ 61,324 (1987).

its suppliers to buyout take-or-pay exposure and reform contracts.

Furthermore, Tennessee's customers have been aware that they might share in the allocation of take-or-pay costs. In Order No. 380,[10] the Commission put customers on notice that the issue of take-or-pay cost recovery would be addressed in the future. Thus, in this case, not only has notice been provided through Order No. 380, but also the cost recovery mechanism is not related to expenses that should have been paid in the past. Rather, at issue here is the appropriate allocation of current settlement payments.

Another allocation issue raised by the Tennessee settlement proposal is whether Tennessee should be allowed to use a composite allocation factor, based on the estimated ⅓-⅔ split between take-or-pay buyout and buydown costs. Several parties argue that this weighting is not supported by the record. The Commission disagrees.

The evidence substantiates Tennessee's expectations that ⅓ of its take-or-pay costs will relate to settlement of take-or-pay claims and ⅔ to contract reformation. The present value of differences between contract prices and spot market prices under Tennesee's contracts totalled \$1.5 billion through 1985.[11] Tennessee's corresponding adjusted take-or-pay exposure through 1985 was \$1.75 billion. Based on contract reformation settlements of 50 cents on the dollar and take-or-pay buyout settlements of 20 cents on the dollar,[12] Tennessee would expend \$750

---

[10] *FERC Statutes and Regulations, Regulations Preambles 1982-1985* ¶ 30,571, at p. 30,971 (1984).

[11] This is shown on a schedule contained in a protested exhibit (Exh. BCN-32), sponsored by New England. The \$1.5 billion total includes \$1.029 billion attributable to Tennessee's top 50 problem contracts.

[12] Tennessee states that from the producers standpoint, contract reformation concessions are of greater value and thus generally command the larger payment.

million for reformation and $350 million for buyout of take-or-pay claims based on 1985 data. This supports Tennessee's 1/3 weighting of the take-or-pay buyout factor and 2/3 weighting of the contract reformation allocation factor to derive the composite allocation percentages contained in Appendix A of its settlement proposal.

Some parties argue that Tennessee should not use a composite allocation factor, based on the estimated 1/3-2/3 split between take-or-pay buyout and contract reformation costs, and instead should apply whatever factor is appropriate (take-or-pay buyout or contract reformation) at the time Tennessee incurs and flows through its costs. In response, Tennessee notes that many of its settlements with producers are likely to be "global" settlements that both resolve take-or-pay claims and reform the provisions of numerous gas purchase contracts with a given producer. In these circumstances, it may be difficult to break down the settlement costs between take-or-pay and contract reformation. Furthermore, Tennessee notes that the use of a predetermined composite allocation factor promotes certainty for the customers.

The Commission agrees with Tennessee on this point. Use of a predetermined composite allocation factor allows each customer to know its maximum liability and to plan accordingly. Waiting until costs are actually incurred to determine the applicable allocation factor could result in increases in costs to be charged to some customers and decreases for others, depending on the division of actual costs between buyout and buydown expenses. This risk of cost shifts among customers could lead to disputes over Tennessee's apportionment of its settlement costs between contract reformation and take-or-pay buyout costs, cause potentially numerous hearings and ultimately delay the final resolution of the contract realignment problem. In view of these considerations, the Commission adopts Tennessee's predetermined composite allocation factor.

H. Gas Inventory Charge

As noted above, Tennessee's settlement proposal contains a provision for continued negotiations with respect to the development of a gas inventory charge. Specifically, Article II, Section 1 states that participants recognize that "it is in the mutual interest of Tennessee and its customers" to put in place for the future a mechanism by which Tennessee would allocate and recover its ongoing costs of maintaining gas supply for its customers. Accordingly, participants would agree to continue negotiation toward establishing a gas inventory charge provision for Tennessee. The proposal further states that nothing in the settlement agreement prohibits Tennessee from unilaterally filing to implement such a provision in its tariff.

Staff suggests that Tennessee's proposal requires clarification to ensure that the $750 million cap applies to all contract reformation costs incurred under any contracts covering existing reserves as well as all costs to resolve take-or-pay liability accrued up to the time of the effectiveness of a gas inventory charge or similar mechanism to recover future take-or-pay costs. In its reply comments filed November 13, 1987, Tennessee states its agreement with Staff's clarification of the cap as a limit on its right to recover take-or-pay costs up until the time it implements a gas inventory charge. Tennessee further states that it intended to be very clear that take-or-pay costs (including contract reformation costs) would only be recovered *either* through the Article I passthrough recovery mechanism *or* a gas inventory charge to be implemented in the future. In fact, Article I, Section 1a defines take-or-pay costs eligible for fixed charge recovery as excluding any costs reflected in the gas inventory charge. This is appropriate.

In addition, certain parties express concern with regard to the costs that may later be eligible for recovery under a gas inventory charge. This is an issue better

left to negotiations in developing that charge. Any commitment to the design of that charge by Tennessee or any other party at this point is premature. Moreover, the settlement does not affect the customers' rights to object to any gas inventory charge ultimately proposed by Tennessee.

I. Contract Reformation

Article II, Section 2 of Tennessee's settlement proposal provides for continued pursuit of modifications of the terms of Tennessee's gas purchase contracts by requesting Commission exercise of its authority under section 5 of the Natural Gas Act (NGA). Specifically, under the language of the settlement proposal, Tennessee agrees that it will continue to pursue section 5 relief from the Commission in the context of the current proceeding in Order No. 500,[13] and, if necessary, any appropriate proceeding established by the Commission in the future. In the event the Commission ultimately modifies the terms and conditions of Tennessee's gas purchase contracts, the settlement proposal states that nothing in its terms shall preclude any resulting benefits of that action from accruing to Tennessee's customers, including a reduction in the customers' maximum liability under the settlement for take-or-pay costs.

Certain parties do not oppose Tennessee's settlement offer, but urge the Commission to reform the terms and conditions of Tennessee's gas contracts either simultaneously with or before taking final action on the settlement proposal. Other parties argue that Tennessee should not be allowed to recover contract reformation costs until after the Commission completes its determination of whether it should take section 5 action to reform producer/pipeline contracts.

---

[13] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, *FERC Statutes and Regulations* ¶ 30,761 (1987) (Interim Rule and Settlement of Policy, Docket No. RM87-34-000). These interim regulations became effective on September 15, 1987.

The competing settlement proposals filed by New England and National Fuel contain provisions for mandatory contract reformation of Tennessee's take-or-pay contracts under section 5. These two proposals are similar and essentially call for affirmative relief. The proposals set forth the criteria for determining which of Tennessee's gas purchase contracts are unjust, unreasonable, unduly discriminatory and preferential; (2) require Tennessee to submit to the Commission a list of its contracts which meet the stated criteria for review by the Commission Staff; (3) call for a Commission order requiring the parties to such contracts to enter into good faith negotiations and to produce revised contracts meeting certain specified criteria, and (4) provide that contracts not meeting the specified criteria within a designated time shall be modified by the Commission to declare the take-or-pay provision null and void.

In addition, New England argues that the effect of the Tennessee Article II, Section 2 provision deprives parties in advance of any right to challenge contracts and amendments executed by Tennessee that do not exist today and that may not exist until a year or two from today. Similarly, Associated Gas Distributors (AGD) contends that the Tennessee proposal would terminate all pending Tennessee proceedings in which the section 5 issue has been raised and preclude any party from challenging Tennessee's contracts under section 5 in the future.

In response, Tennessee urges the Commission to grant approval of a take-or-pay cost passthrough mechanism without waiting to complete its determination of whether it should take section 5 action. Tennessee states that any such delay would bring its contract reformation efforts to a standstill and frustrate its efforts to resolve its take-or-pay problem expeditiously. As a consequence, Tennessee states that the take-or-pay liabilities that could be reduced through reformation will continue to increase dramatically, contrary to the objective of Order No. 500

to resolve this problem quickly and effectively. While Tennessee continues to urge the Commission to take section 5 action, it states that both it and its customers must continue to deal with changes occurring in the market now and cannot afford to wait upon the possibility of some future action outside of their control.

Tennessee also disputes claims that its proposal would terminate all pending Tennessee proceedings in which the section 5 issue has been raised or preclude any party from challenging Tennessee's contracts under section 5 in the future. Tennessee cites the last sentence of Article I, Section 9 of its proposal as fully preserving the section 5 issue of concern to New England and AGD.

The Commission agrees with Tennessee that approval of an appropriate cost passthrough mechanism should not be delayed pending the Commission's consideration of Tennessee's arguments in the Order No. 500 proceeding that it should take section 5 action. Tennessee has committed in its proposal to continue to urge section 5 relief. At the same time, it recognizes that the Commission's decision making process on the section 5 issue should not delay the resolution of the equally important take-or-pay cost recovery issues presented to the Commission here. As noted by Tennessee, deferral of a final Commission decision in this case could slow the contract reformation process, contrary to the interests of both Tennessee and its customers.

In addition, the Commission concurs with Tennessee that its proposal will not interfere with parties seeking section 5 relief to Tennessee's contracts. While Article I, Section 9 of the settlement precludes challenges regarding the prudence of Tennessee's existing contracts, it also states that nothing therein shall preclude the Commission from instituting a proceeding under Section 5 of the Natural Gas Act with regard to the terms and conditions of Tennessee's existing gas purchase contracts nor from

exercising whatever authority it has to modify those contracts.

J. Standby Sales Service

Tennessee's settlement proposal also provides for new standby sales service in accord with the Commission regulations at 18 C.F.R. section 284.10 for Tennessee's Rate Schedule CD, G and GS customers electing to convert to firm transportation. Under Article III, Section 1a, a Commission order approving Tennessee's proposal shall constitute (1) authorization pursuant to Section 7 to provide standby sales service under terms and conditions set forth in revised tariff sheets attached to the settlement proposal as Appendix C and (2) pre-granted abandonment authorization to terminate this service effective February 1, 1989.

In comments filed in support of its proposed settlement, Tennessee explains that during the litigation phase of this proceeding, it opposed any requirement that it provide standby sales service as the *quid pro quo* for implementation of its take-or-pay cost recovery mechanism. Tennessee argued then that standby sales service would require it to maintain long-term gas supplies without any guarantee that standby service customers would actually purchase gas from Tennessee. Without a permanent mechanism in place to recover the ongoing costs of maintaining gas supply, standby service could exacerbate the take-or-pay problem.

Tennessee now states, however, that for purposes of resolving this proceeding, it is willing to take an additional risk for a limited period and provide standby service until February 1, 1989. Tennessee repeats its intention to vigorously pursue development of a gas inventory charge and explains that if such pursuit is successful, it has agreed in its settlement proposal to continue the standby sales service beyond February 1, 1989. In sum, Tennessee is not opposed to providing standby service on

a permanent basis so long as it has a mechanism in place for recovery of supply maintenance costs.

Staff argues that the rate applicable to the standby sales service established under Article III of the settlement is not properly designed. Citing *Transcontinental Gas Pipe Line Corp.*,[14] it contends that a properly designed standby rate should be based on representative levels of standby service and should include only the costs of facilities necessary to provide the service.

Certain customers propose to require Tennessee to provide permanent and unrestricted standby sales service. National Fuel Gas Supply Corporation, objects to Article III, Section 4 of the Tennessee proposal, which if approved would grant Tennessee abandonment for any sales service converted by the customers to firm transportation if the customer does not elect standby service. There is also objection to Article III, Section 3b which provides for prospective termination of CD conversion rights if 18 C.F.R. § 284.10 is eliminated by Commission or court order.

As a general matter, the Commission is favorable to Tennessee's effort to establish a standby sales service. However, because the standby sales proposal represents a change in pipeline service, Tennessee must file for certificate authorization so that this new service can be properly noticed. Tennessee appears to have recognized this since its settlement proposal contemplates section 7 authorization.

In addition, the Commission agrees with Staff's argument that the rate applicable to the standby sales service as currently established under the settlement proposal is not properly designed. In the Commission's view, a properly designed standby charge should recover only those costs which the pipeline incurs to stand ready to resume sales service should the firm sales customer elect

---

[14] 38 FERC ¶ 61,165, at p. 61,488 (1987).

to purchase gas from the pipeline rather than the transportation service. The pipeline would not incur variable production costs related to the displacement sale. Accordingly, the standby charge might include fixed products extraction costs, pipeline supplier demand charges, Account No. 858 "as billed" demand charges, and fixed gathering costs that are not reflected in the transportation rate.

An acceptable approach to derivation of a standby charge is to identify costs that the pipeline would recover through its sales rate that it would not recover through its firm transportation rate. These costs, less any variable costs not incurred because of sales displacement, provide the basis for the standby charge. Tennessee has not taken this approach. Under the settlement proposal, Tennessee's standby charges simply represent an indifference charge equal to the non-gas component of its sales rates. Thus, it appears that Tennessee's standby charge includes variable costs such as Account No. 858 commodity costs (transmission and compression by others) that it does not incur to standby to sell gas.

In addition to these problems with the proposed standby rate, Article III, Section 4 of the Tennessee proposal contemplates that the Commission would authorize pre-granted abandonment. Such pre-granted abandonment is not normally authorized; instead, the pipeline must file to abandon the service. The Commission finds nothing in the settlement that would justify pre-granted abandonment authorization here.

In light of these specified concerns, Tennessee's proposed standby sales service cannot be approved at this time. Instead, the Commission will require Tennessee, as a condition to approval of its settlement proposal, to file an application for certificate authorization to provide this service. This filing should be made within 30 days of the issuance of this order and should reflect the concerns outlined in the above discussion.

K. Other Related Issues

1. Prior Take-or-Pay Funding Settlements

Article I, Section 1a of the Tennessee proposal defines recoverable take-or-pay costs to exclude payments funded by Tennessee customers under the settlement agreement of April 11, 1986, in Docket No. RP85-178 *et al.* (April 11 Stipulation). Article IV, Section 1a states that on the first day of the month following the effective date of the settlement in this proceeding, Tennessee shall cease any direct billing of the take-or-pay costs pursuant to the April 11 Stipulation.

The April 11, 1986 settlement agreement approved in Docket No. RP85-178-000 *et al.*, resolved outstanding issues in certain Tennessee rate proceedings. Article I, Section 2 of that agreement provides for direct billing of the cost-of-service effect of take-or-pay prepayments and take-or-pay buy-out costs. Tennessee is to bill each of 10 named customers an annual amount for the customer's allocable share of the stipulated annual settlement take-or-pay cost of $14,121,733.

The customer's share is based on the ratio of (1) each customer's deficiencies in takes below 82 percent of its AQL for calendar year 1984 under all rate schedules (Deficiency Quantity) to (2) the sum of all customers' deficiency quantities. However, the share of the settlement take-or-pay cost otherwise allocable to customers served under Rate Schedules G and GS is allocable to and absorbed by Tennessee.

Certain parties object to the termination of take-or-pay direct billing under the April 11 settlement in Docket No. RP85-178 upon commencement of take-or-pay cost recovery under the proposal at issue here. By the terms of the April 11 settlement, it is to remain in effect and can be terminated by the occurrence of one of three enumerated events. These are (1) a superseding general rate change filed by Tennessee pursuant to section 4(e) of the

NGA, (2) a restatement of rates pursuant to 18 C.F.R. § 154.38(d)(vi)(2), or (3) a rate change resulting from a proceeding instituted by the Commission pursuant to section 5 of the NGA. Equitable Gas Company (Equitable) and others argue that none of these events has occurred, and that Tennessee has no authority to diminish unilaterally any rights under the April 11 settlement.

Tennessee responds that the terms of the settlement in Docket No. RP85-178-000 permit the Commission to terminate any aspect of that settlement pursuant to a proceeding initiated under section 5 of the NGA. In Tennessee's view, this Docket No. RP86-119-000 is such a proceeding as indicated by the Commission's order in the case rejecting Tennessee's filing and instituting a hearing under authority of sections 4, 5, 16 and 17 of the NGA.

Tennessee states further that the arguments raised against termination of direct billing under the Docket No. RP85-178-000 settlement are arguments against changing the allocation methodology used in that docket. Tennessee believes that although the Docket No. RP85-178-000 methodology was appropriate in that proceeding to apportion a very limited representative level of costs based for the most part on a snapshot of actual costs on Tennessee's books prior to its embarking on concentrated negotiations with producers, it should not be maintained for the very much greater costs at issue here which are attributable to a much broader period.

The Commission agrees with Tennessee that the settlement in Docket No. RP85-178-000, under its own terms, can be terminated. In Docket No. RP86-119-000, the Commission instituted a hearing under section 5 of the NGA. After reviewing the proposal in the latter docket, the Commission finds under section 5 that to allow continuation of the earlier settlement in Docket No. RP85-178-000 simultaneously with the settlement approved in this docket would be unjust, unreasonable, unduly dis-

criminatory and preferential. While the Docket No. RP85-178-000 cost allocation methodology was appropriately used in that proceeding, it should not be maintained for the much greater costs at issue here. Moreover, Article I, Section 1 of the proposal in this case precludes Tennessee from double-dipping by collecting the same costs under this and any earlier settlements. In addition, with respect to other, earlier Tennessee take-or-pay funding settlements, Article IV, Section 2 of the Tennessee proposal here leaves intact provisions in earlier settlements with respect to amounts that Tennessee agreed to absorb under those earlier agreements. Thus, the Tennessee proposal balances the interests of customers previously billed take-or-pay costs, while meeting the current need to use a cost allocation method predicated on a much broader basis.

2. *Calculation of Columbia and Inland Allocation Factors*

Both Columbia Gas Transmission Corporation (Columbia) and Inland Gas Company, Inc. (Inland) oppose the use of annual contract quantity determinants, particularly those in effect during periods as early as 1981, in deriving each customer's proportionate contractual level. Irrespective of whether this part of Tennessee's proposed formula is modified, however, both Columbia and Inland state that Tennessee has in any event misstated their particular contractual levels in the portion of the allocation formula based on customers' average annual quantity limitation for the period 1981-1985.

Columbia and Inland state that Tennessee's computation fail to take into account the reductions effective November 1, 1984 in their separate contracts with Tennessee pursuant to a settlement in Docket No. CP84-441-000 *et al.* Columbia and Inland request the Commission to modify the settlement proposal to correct this.

Tennessee responds that this proposed adjustment should be rejected because it is premised on an improper effective date for reductions. The Commission agrees.

The settlement in the CP Docket did not become effective until February 1986. Pursuant to its terms, Columbia's and Inland's sales entitlements were to be reduced on the first day of the month after that. Thus, it was not until March 1, 1986, that Tennessee was authorized to abandon service to Columbia and Inland as provided in the Settlement agreement. Until that time, Tennessee was obligated to provide sales service up to Columbia's and Inland's contractual levels without regard to the pending reductions. This was the case even though in a later provision of the settlement Tennessee was obligated to implement a rate reduction for reducing customers effective November 1, 1984. Accordingly, the allocation percentages shown on Appendix A of the Tennessee settlement proposal reflect reduction in AQL for Columbia and Inland effective March 1986.

3. Storage Service for Third-Party Gas

As part of this settlement, Public Service Electric and Gas Company (PSE&G) would require Tennessee to file amendments to its Rate Schedules SS-E and SS-NE to permit storage of gas from any source up to 100 percent of the customers' maximum storage quantity. Currently, Tennessee offers storage service under these rate schedules to customers for gas purchased from Tennessee.

The suggestion by PSE&G will not be adopted. Tennessee has filed in Docket No. CP87-103-000 to open one-third of its contract storage to third-party gas, and that case is currently pending before the Commission. That proceeding is the more appropriate forum in which to address this issue.

4. FT-A Rate Schedule

PSE & G objects to the provision of the FT-A Rate Schedule that limits to five the number of receipt points

a shipper may designate. Tennessee filed Rate Schedule FT-A together with other rate schedules and tariff terms and conditions pertaining to open-access transportation in Docket No. RP87-26-000. The Commission has now approved Tennessee's five-receipt point provision as in compliance with the Commission's requirements. *See Tennessee Gas Pipeline Company*, 41 FERC ¶ 61,161 (1987).

5. Passthrough by Downstream Pipeline Customers

Numerous parties including Staff complain that Tennessee's settlement proposal inappropriately restricts their rights concerning the passthrough of take-or-pay charges by Tennessee's downstream pipeline customers. Article I, Section 9 provides that rates and charges billed pursuant to the settlement shall be deemed just and reasonable for purposes of section 4 and 5 of the NGA and shall be eligible for recovery by any customers whose rates are subject to FERC jurisdiction without further challenge by any party or staff.

The Commission agrees that the guaranteed passthrough provision must be eliminated before Tennessee's proposed settlement can be approved. The rate proceedings of Tennessee's customers are the appropriate place to address the rates charged by those customers. The Commission explicitly stated when adopting the policy statement in Order No. 500 that the purchasing practices of downstream pipelines are subject to prudence challenges in connection with the downstream pipeline's incurrence of take-or-pay charges from their upstream pipeline suppliers.

6. Tariff Sheets; Settlement Effective Date

Some objection was raised to the portions of Articles I and III of Tennessee's proposal which provide that the tariff sheets implementing the settlement shall be accepted without suspension or refund obligation. Article III pertains to the standby sales service consideration of which

is being deferred. With respect to Article I, Section 7, relating to Tennessee's semiannual filings to update its take-or-pay surcharges, the tariff sheets are only to be made effective "to the extent consistent with the terms of this Stipulation."

Equitable requests that any settlement in this case should be made effective only after the Commission order approving the settlement has been sustained on judicial review. To grant that request would equal an inappropriate stay of the Commission's order and frustrate Commission and industry efforts to resolve take-or-pay issues.

At the same time, Tennessee requests in its comments that it be protected from undercollection due to any court-ordered changes in cost allocation. Specifically, Tennessee asks the Commission to place all participants on notice that it will be permitted to reallocate its take-or-pay costs among customers as required to comply with any court decision or Commission order on remand and to collect from each customer the amount, including interest, that Tennessee would have collected had it allocated its take-or-pay costs from the outset in the manner ultimately approved by the Commission or the court.

Although Tennessee's concern is understandable, it would be premature to attempt to anticipate such events. Indeed, it would be inappropriate, if not impossible, for the Commission to state a guarantee about cost recovery based on unknown future Commission or court decisions.

7. *Interventions/Late Filings*

The joint motion to intervene out of time filed November 3, 1987 by The Cincinnati Gas & Electric Company and The Union Light, Heat and Power Company is unopposed and is granted.

The separate motions to accept late-filed comments filed by Northern Indiana Public Service Company and Consolidated Gas Transmission Corporation on November 4, 1987

and November 24, 1987, respectively, are likewise unopposed and are granted.

The Commission orders:

(A) Subject to the modifications, conditions, and clarifications in this order, the offer of settlement filed by Tennessee, on October 14, 1987, is approved.

(B) Approval of Tennessee's settlement filed October 14, 1987, is also subject to Tennessee's submitting to the Commission, in addition to the reporting obligation set forth in Article I, Section 8 of the Tennessee settlement, details of the costs included in the filing, including copies of each settlement agreement entered into and an explanation of what each settlement entails.

(C) Approval of Tennessee's settlement filed October 14, 1987, is also subject to Tennessee's filing within 30 days of the issuance of this order, an application for a certificate amendment to provide a standby sales service.

(D) Within 15 days of the issuance of this order, Tennessee shall file revised tariff sheets in lieu of those at issue herein, in accordance with the terms of the settlement, this order, and the Commission Rules and Regulations.

(E) The joint motion to intervene out of time filed November 3, 1987, by The Cincinnati Gas & Electric Company and The Union Light, Heat and Power Company is granted subject to the rules and regulations of the Commission provided, however, that its participation shall be limited to matters affecting asserted rights and interests set forth in its motion to intervene, and provided, further, that its admission shall not be construed as recognition that it might be aggrieved by any order entered in this proceeding.

Commissioner Sousa *concurred* with a separate statement attached.

Anthony G. SOUSA, Commissioner, concurring:

I concur in approving Tennessee Gas Pipeline Company's (Tennessee) Order No. 500 take-or-pay settlement with reluctance. As indicated in my concurrence to Order No. 500,[1] the 50-50 sharing of take-or-pay costs is meaningless unless the Commission finds that the underlying transaction between the pipeline and the producer is itself reasonable.

Under this order, Tennessee is permitted to pass on one-half ($650 million) of total payments to producers, averaging approximately 43 cents on the dollar[2] of accrued take-or-pay liability, without Commission review. This appears to be a relatively high cost settlement, and illustrates my concern with the Commission's failure to consider these underlying costs as part of its take-or-pay policy statement in Order No. 500.

---

[1] *FERC Statutes and Regulations* ¶ 30,761, at p. 30,806.

[2] Total take-or-pay liability is $3 billion through 1986 (Mimeo page 10, footnote number 5). Tennessee estimates total payments to non-affiliated producers at $1.3 billion.

APPENDIX F

FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. RP86-119-007, TA84-2-9-009 and TA85-1-9-006

TENNESSEE GAS PIPELINE COMPANY
a division of Tenneco Inc.

ORDER DENYING IN PART AND GRANTING IN PART REHEARING

(Issued May 27, 1988)

Before Commissioners: Martha O. Hesse, Chairman; Anthony G. Sousa, Charles G. Stalon and Charles A. Trabandt.

On February 8, 1988, the Commission issued an order approving with modification a contested offer of settlement, filed October 14, 1987, by Tennessee Gas Pipeline Company (Tennessee).[1] Tennessee filed its settlement offer to resolve issues in Docket No. RP86-119-000 and certain other dockets[2] and to establish procedures to recover certain take-or-pay costs under the policies of Order No. 500.[3]

In the order, issued February 8, 1988, the Commission approved but modified Tennessee's settlement proposal. These modifications included the disallowance of affiliate

---

[1] 42 FERC ¶ 61,175 (1988).

[2] Docket Nos. TA84-2-9-007 and TA85-1-9-004.

[3] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, *FERC Statutes and Regulations* ¶ 30,761 (1987) *promulgating* Section 2.104 of the regulations, *to be codified at*, 18 C.F.R. § 2.104.

take-or-pay costs, the exclusion of take-of-pay prepayments and related carrying costs, and the elimination of the guaranteed passthrough provision for downstream pipeline customers.

Virtually all parties, including Tennessee, filed requests for rehearing of the February 8, 1988 order. Parties address numerous issues involving various aspects of the approved proposal. Discussed below are the issues raised by the requests for rehearing. The Commission is granting in part and largely denying rehearing as discussed below.

Discussion

A. Preliminary Matters

The petition for rehearing filed by the Tennessee Small General Service Customer Group (SGS) includes a motion requesting the Commission to stay the effectiveness of its decision in this case during any judicial appeal. SGS argues that the judicial criteria for a stay are present in this case. It cites: (1) there exists a substantial case on the merits involving a serious issue; (2) the petitioner will be irreparably injured if not granted the relief sought; (3) the issuance of a stay will not substantially harm other parties; and (4) the issuance of a stay will not interfere with the public interest.

Tennessee opposes this motion arguing that: (1) a stay would be contrary to efforts by the Commission and the industry to quickly resolve take-or-pay issues; (2) SGS's request is virtually identical to the request of Equitable Gas Company (Equitable) which the Commission rejected in the prior order; and (3) SGS's motion fails to satisfy the legal standards governing stays.

The Commission agrees with Tennessee that no stay is warranted in this proceeding. A stay would frustrate the Commission's and the industry's efforts to resolve the take-or-pay problem expeditiously and would interfere

with Tennessee's contract reformation efforts. As a consequence, take-or-pay liabilities that could be reduced through reformation could continue to increase, contrary to the public interest.

By motion filed April 13, 1988, Tennessee requests the Commission to strike or disregard certain rehearing requests to the extent these requests are inconsistent with the original comments filed by these same parties. In addition, Tennessee asks the Commission to strike the entire rehearing request filed by Elizabethtown Gas Company, since that company filed no comments on the settlement agreement.

Several of the parties named by Tennessee in its motion object, arguing that their rehearing requests restated prior objections to the settlement or that the rehearing requests arise out of the Commission's modification of Tennessee's proposal. They also argue that Tennessee's motion is an answer to the rehearing requests and is therefore impermissible under Rule 713(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d) (1987).

Contrary to the arguments of Tennessee, many of the issues raised in the cited rehearing requests were in fact raised in prior comments. Furthermore, the Commission believes that its modification of the settlement raised additional issues which are properly discussed in the rehearing requests. The Commission recognizes that the take-or-pay issues in this and other proceedings are complex and may have far-reaching effects. Because of the nature of the problem, it is preferable to provide for a complete examination of the issues involved rather than to narrowly interpret the rules of procedure, effectively denying consideration of these matters. Accordingly, Tennessee's motion is denied.

B. Prudence

Several parties seeking rehearing either request clarification of or object to the manner in which the approved

settlement offer resolves issues concerning the prudence of Tennessee's gas purchasing practices, existing gas purchase contracts and contract reformation efforts. Under the approved settlement offer, 50 percent of Tennessee's non-affiliate take-or-pay costs would be absorbed by Tennessee and the remaining 50 percent would be recovered from Tennessee's customers using a fixed take-or-pay charge. The approved settlement offer provides that as a condition of Tennessee's agreement to absorb 50 percent of its take-or-pay costs, any party accepting the settlement is precluded from challenging the prudence of Tennessee's purchasing practices and existing gas purchase contracts. In addition, parties accepting the settlement offer cannot challenge the prudence of Tennessee's contract reformation costs. The February 8, 1988 order gives all parties the opportunity to reject the settlement and to challenge the prudence of Tennessee's actions.[4] This approach is consistent with Order No. 500.

When adopting the alternative passthrough mechanism outlined in Order No. 500, the Commission sought to avoid lengthy and potentially complex hearings involving an attempt to quantify and ascribe blame for the accumulation of pipeline take-or-pay liabilities. Accordingly, the Commission employs a rebuttable presumption that the pipeline's buyout and buydown costs are prudently incurred. The pipeline's willingness to absorb a significant share of these costs suggests that the presumption is reasonably applied in this context.

In addition, the Commission stated in Order No. 500 that it would, if it appeared reasonable and permissible to do so, approve contested take-or-pay settlement offers as to consenting parties and would initiate hearings as to opposing parties. In cases where a hearing is held, the Commission stated that it would give a pipeline the oppor-

[4] Any party wishing to challenge the prudence of Tennessee's actions was requested to state this in its petition for rehearing, 42 FERC ¶ 61,175, at p. 61,626 (1988).

tunity to recover from litigating parties their proportionate share of all the pipeline's take-or-pay costs found to be prudent, even if the amount allowed were greater than the amount initially claimed by the pipeline. This provision was considered reasonable in view of the fact that any costs found to be imprudent would be disallowed.

Tennessee's approved settlement offer is consistent with this policy. The settlement proposes an equitable sharing (50/50) of Tennessee's take-or-pay buyout and buydown costs and provides that acceptance of the settlement precludes challenges to the prudence of Tennessee's purchasing practices, existing gas purchase contracts, and contract reformation efforts. Any non-consenting party is free to reject the settlement offer and may continue to litigate prudence. Tennessee will have the opportunity to collect from litigating parties their proportionate share of all Tennessee's take-or-pay buyout and buydown costs found to be prudent.

The discussion of the approved settlement offer and its consistency with the policies in Order No. 500 is important to note because many of the objections on rehearing in this case are essentially attacks on the Commission's policies adopted in Order No. 500. The remaining objections stem from confusion over the exact meaning of certain language in the February 8, 1988 order. The specific objections are discussed below.

Most parties seeking rehearing object to the Commission's disposition of the prudence issue for one or more of the following reasons: (1) the rebuttable presumption of prudence given Tennessee's settlement offer is unreasonable, (2) the order forces parties to decide whether to litigate prudence in advance of the issuance of a final order, (3) the order prejudges the outcome of any further prudence challenge, (4) the order deprives parties of due process, (5) the order is a violation of the filed rate doctrine because it subjects parties litigating prudence to greater take-or-pay liability, and (6) the pre-

sumption that Tennessee's contract reformation expenditures are prudent, since the pipeline must absorb 50 percent of these costs, is invalid. The Commission disagrees with these objections.

In their joint petition for rehearing Baltimore Gas & Electric Co., Washington Gas Light Co., Office of Consumers' Counsel, State of Ohio, and the Maryland Public Service Commission (BG&E *et al.*) ask for several clarifications of the February 8, 1988 order. The Commission order mentioned BG&E *et al.*, as the only parties that "appear to continue to question Tennessee's prudence." [5] BG&E *et al.*, as well as Tennessee, interpret this language to mean that BG&E *et al.*, are the only parties who can continue to raise the prudence issue. This is not a correct reading of the Commission's order. All parties have the choice to either accept the offer of settlement or continue to litigate prudence.

BG&E *et al.*, request clarification on whether the prudence issue has already been decided by the Commission in its order approving the settlement offer. They point out that the Commission introduced its discussion of prudence in the order by stating that "no serious allegation of imprudence has been raised as an obstacle to Commission approval of a settlement proposal in this case" and ask whether this is a decision on the merits.

The statement in the Commission order regarding "no serious allegation of imprudence" is a reference to the round of comments and replies filed in response to Tennesee's offer of settlement. It was intended to state that in those comments, parties did not raise prudence as an obstacle to approval of a settlement agreement in this proceeding. Instead, the comments contained various modifications to the Tennessee stipulation and agreement. The Commission's statement in the prior order was not meant to decide the substantive issue of Tennessee's prudence.

[5] 42 FERC ¶ 61,175, at p. 61,626 (1988).

which was a central issue in the hearing before the administrative law judge (ALJ).[6] The Commission emphasizes that its order approving Tennessee's settlement offer is not a decision on the merits regarding prudence, and the order does not prejudge the outcome for any party that wishes to continue to litigate prudence.

Several parties contend that a decision on the record in Docket No. RP86-119-000 is required before permitting Tennessee to implement its settlement offer. We disagree. There is no basis to the contention that Tennessee cannot file to recover take-or-pay buyout and buydown costs under the alternative, equitable sharing mechanism of Order No. 500 before a final Commission decision in a pending rate case. The policy stated in Order No. 500 requires customers to choose between either an equitable sharing of costs proposed by Tennessee with the presumption of prudence, or pursuing litigation of the prudence issue. To issue a decision in Docket No. RP86-119-000 prior to that election would render such a choice meaningless.[7]

Nor is it any bar to approving a settlement offer after an ALJ has made a prudence determination with respect to take-or-pay costs. Under the Commission's rules, an initial decision that is appealed to the Commission is not a final agency order but has the status of a recommended decision only. Of course, where Commission action is pending in a rate proceeding, the record established before the ALJ will not be ignored. In this case, if a party rejects Tennessee's settlement offer and litigates prudence, the Commission will rely on the record established in Docket No. RP86-119-000 to decide the amount of costs to be paid by that party.

The Public Service Commission of the State of New York (PSCNY) objects to insulating Tennessee's contract reformation costs from review and challenge. PSCNY

[6] *See* 40 FERC ¶ 63,008, at pp. 65,072-65,080 (1987).

[7] *Transcontinental Gas Pipe Line Corp.*, 42 FERC ¶ 61,407 (1988).

points out that the prudence of Tennessee's contract reformation practices were not at issue in the hearings in this proceeding. That Tennessee's contract reformation practices were not at issue in the hearing does not preclude Tennessee from making this offer that would avoid litigation of that issue. Any party may reject the settlement offer and litigate the prudence of Tennessee's contract reformation expenditures if it so chooses. To the extent necessary, supplemental hearings may be required to obtain evidence on Tennessee's contract reformation expenditures.

In their petitions for rehearing, Elizabethtown Gas Company (Elizabethtown) and Joint Intervenors[8] object to the rationale for presuming that Tennessee's reformation costs will be prudent. The Commission order stated that because Tennessee will absorb 50 percent of its take-or-pay reformation costs, it will bargain seriously as it renegotiates its contracts. Joint Intervenors object to this reasoning. They argue that whether or not Tennessee is forced to absorb a portion of its take-or-pay costs is irrelevant with respect to the bargains Tennessee has already entered, either in initially incurring take-or-pay obligations or in renegotiating these contracts. Elizabethtown argues that costs are not just and reasonable simply because they are the product of arms-length bargains with producers. Both Elizabethtown and Joint Intervenors are, in essence, objecting to the policies of Order No. 500, which have been addressed and affirmed in other proceedings.[9] The Commission, therefore, affirms the presumption of prudence applied to Tennessee's filing.

Columbia Gas Distribution Company (Columbia Gas) and BG&E *et al.* object to the Commission's allowing Tennessee the opportunity to recover from those parties that

---

[8] Joint Intervenors include numerous individual parties to this proceeding, many of whom also filed separate requests for rehearing.

[9] *See, e.g., United Gas Pipe Line Company,* 41 FERC ¶ 61,381 (1987), *reh'g denied,* 42 FERC ¶ 61,197 (1988).

choose to litigate prudence their proportionate share of all of Tennessee's take-or-pay costs found to be prudent "even if the amount allowed is greater than the amount initially claimed by [Tennessee]."[10] BG&E *et al.* requests clarification of this phrase. It states that its choice of whether to accept Tennessee's approved settlement offer or to continue to litigate prudence is dependent on the magnitude of this "penalty."

If a party continues to litigate prudence and Tennessee is found to have been prudent, the litigating party would be liable for its proportionate share of all of Tennessee's take-or-pay buyout and buydown costs. The phrase "greater than the amount initially claimed by the pipeline" refers to the amount the party would have been responsible for if it had accepted Tennessee's settlement proposal. In other words, if the record demonstrates that the pipeline is entitled to recover more costs than it originally sought to recover, the Commission would permit the pipeline to file to recover the additional costs that were justified by the record. Contrary to arguments made by certain parties, the Commission is not coercing any one to accept Tennessee's approved settlement offer. The Commission's order simply requires a party to choose whether to litigate prudence or whether to accept Tennessee's settlement offer. The choice whether to accept a settlement proposal over continued litigation is the type of decision routinely made in a litigated proceeding, and each party must make its own assessment as to whether it would do better by settling or by litigating.

In light of the above, particularly the apparent confusion of the parties, any party wishing to continue to challenge the prudence of Tennessee's purchasing practices and existing gas purchase contracts must file a statement with the Commission within 15 days of the issuance of this order on rehearing. That statement should indicate

---

[10] 42 FERC ¶ 61,175, at p. 61,626 (1988).

the party's intention to litigate the prudence issue. Unless a party so files, it will be considered to have consented to the approved settlement agreement.

C. Cap on Cost Recovery/Affiliate Costs

Under the Tennessee settlement offer as originally proposed, the customers' share of take-or-pay costs was limited by a total cap of $750 million, which included a separate cap of $100 million applicable to affiliate take-or-pay costs. The Commission rejected Tennessee's proposal to recover affiliate take-or-pay expenses. It also reduced the cost cap from $750 million to $650 million.

Tennessee objects to the reduction of the cost cap, asserting that the decision to reduce the cap is based on the erroneous assumption that the $750 million was divided into two distinct segments—$650 million for non-affiliate take-or-pay costs and $100 million for affiliate take-or-pay costs. Tennessee argues that its settlement offer would have permitted it to use the cost cap to recover either $750 million in non-affiliate take-or-pay costs or a combination of non-affiliate take-or-pay costs and affiliate costs up to $100 million. Tennessee asserts that had it elected not to recover affiliate take-or-pay costs, the entire $750 million cap would have been available for recovery of non-affiliate take-or-pay costs. While Tennessee believes it should be able to recover affiliate take-or-pay costs, it alternatively requests that it be allowed to use the full $750 million cap for recovery of non-affiliate take-or-pay costs. Since Order No. 500 does not require any cap whatsoever, Tennessee believes the cost cap "volunteered" by Tennessee should not be reduced.[11]

---

[11] The Producer Associations express concern that Tennessee would use the cost gap as a pretext to invoke regulatory out clauses in specific Tennessee contracts. Although the concern is speculative at this time, the Commission does note that the approval of this settlement proposal by itself does not disallow the passthrough of any costs.

The Commission affirms the decision to establish a $650 million cap on the customers' share of take-or-pay costs. The Commission assumes that Tennessee had some basis to include the possible recovery of up to $100 million of affiliate take-or-pay costs when it proposed the $750 million cap, and that Tennessee would have attempted to recover approximately that amount of affiliate costs. Accordingly, the Commission adjusted downward the $750 million cap when it eliminated the $100 million component for affiliate take-or-pay costs. As discussed below, the Commission continues to reject recovery of affiliate take-or-pay costs through the equitable sharing pass-through mechanism, and emphasizes that the $650 million cost cap is for recovery of non-affiliate take-or-pay costs only.

Although denying Tennessee the opportunity to recover affiliate take-or-pay costs as a part of its settlement offer, the Commission stated in the prior order that Tennessee could make a separate filing to recover such costs. The Commission further stated that it would permit take-or-pay buyout and buydown payments paid to an affiliate to be passed through only in the commodity component of the pipeline's sales rate.

Most parties were in favor of denying Tennessee's recovery of affiliate take-or-pay costs as part of its settlement offer. In addition, some parties objected to allowing Tennessee the right to make any separate filings to recover take-or-pay payments to its affiliates. These parties assert that precluding any recovery of affiliate costs is consistent with Order No. 500.

Alabama-Tennessee Natural Gas (Alabama-Tennessee) and BG&E, *et al.* are concerned that Tennessee may be able to recover affiliate costs in an indirect manner. Alabama-Tennessee postulates that an affiliate of Tennessee could sell reserves currently under contract to Tennessee to a third party. Those reserves might include gas for which Tennessee may be liable for take-or-pay payments.

In such a situation, Alabama-Tennessee requests the Commission to find that the third party stands in the shoes of the affiliate, so that Tennessee cannot recover any take-or-pay payments made to that third person.

BG&E *et al.* asserts that during the early 1980's, Tennessee intentionally shifted affiliate take-or-pay liability to non-affiliate producers pursuant to a policy of preserving and expanding the market share of its affiliate producers. BG&E *et al.* asks that the Commission amend its order to account for Tennessee's maximization of affiliate purchases which caused increased take-or-pay exposure to non-affiliate producers. In the view of BG&E *et al.*, the Commission's simply exclusion of affiliate costs from Tennessee's direct billing mechanism is not an adequate remedy, since it allegedly overlooks the fact that Tennessee's practice of affiliate favoritism was a cause of non-affiliate buyout and buydown costs.

The arguments raised by BG&E *et al.* are an effort to ascribe blame or fault for Tennessee's take-or-pay liabilities. The very purpose of the Commission's passthrough policies is to avoid an inquiry such as urged by BG&E *et al.* However, BG&E *et al.* can, if it chooses, litigate this issue, but the Commission will not modify or reject Tennessee's proposal on this ground. The hypothetical raised by Alabama-Tennessee and BG&E, *et al.* as to the possibility of indirect recovery of affiliate costs is, at this juncture, too speculative. When Tennessee makes appropriate filings to document its actual expenditures, the Commission and the parties can scrutinize the transactions and take any action that might be appropriate to insure compliance with the conditions of the Commission's orders concerning payments to affiliates.

In contrast to the arguments above, Tennessee believes that the Commission should amend its order to reinstate the provision of the settlement offer allowing recovery of affiliate costs. Tennessee had proposed that prior to recovery of any of its affiliate costs, it would submit to all

parties and Commission staff information sufficient to support recovery of such costs. If any protests were filed, the Commission was to establish procedures for examining the comparability of the affiliate payments with those made to third parties.

Tennessee also objects to the Commission's ruling that requires Tennessee to make a separate filing to recover payments to affiliates and restricts passthrough of affiliate take-or-pay buyout and buydown costs to the commodity component of the pipeline's sales rates. Tennessee argues that commodity rate treatment of affiliate take-or-pay costs is inappropriate for the same reasons that it is inappropriate for non-affiliate take-or-pay costs, i.e., that commodity rate treatment of affiliate costs will impact only those customers who continue to purchase from Tennessee, while customers who buy elsewhere will avoid all take-or-pay responsibilities.

The Commission affirms its order with respect to recovery of take-or-pay payments to affiliate producers. No affiliate costs can be recovered by Tennessee as part of the approved settlement offer. If Tennessee wishes to recover such costs, it must make a separate filing to do so and recovery will be restricted to passthrough in the commodity component of Tennessee's sales rates. In the case of payments to affiliates, Tennessee's agreement to absorb a share is insufficient to base a presumption that the costs are prudently incurred. Such negotiations between affiliates do not provide the same assurance that hard bargaining occurred as with unaffiliated producers where the pipeline is absorbing some of the costs. Therefore, in order to reasonably apply a presumption of prudence to payments to affiliates (and speed the resolution of take-or-pay liabilities), these payments must be recovered through the commodity component of Tennessee's rates. In this way, the risk that these costs will not be recovered unless Tennessee's overall gas costs are competitive provides a comparable assurance that the amount of costs paid to the affiliates is likely to be reasonable.

As a final note, the Commission does not agree with Tennessee that commodity rate treatment of take-or-pay costs is inappropriate for non-affiliate take-or-pay costs. Indeed, commodity recovery is the principal method approved by the Commission for the recovery of such costs and the equitable-sharing method is a permissible exception to the general rule.[12]

D. Recovery of Prepayment

Tennessee's settlement proposal defined take-or-pay costs to include the cost of service effect of prepayments (committed by Tennessee on or before December 31, 1989) to satisfy take-or-pay claims under existing gas purchase contracts. The Commission modified Tennessee's settlement offer to exclude prepayments. The Commission noted that Order No. 500 and the proposed policy statements which preceded it,[13] consistently referred to only take-or-pay buyout and buydown costs.

All parties, with the exception of Tennessee, generally favor the exclusion of prepayments. Joint Intervenors and others agree with excluding recovery of prepayments from the settlement offer, but request that the Commission reduce the cost cap on Tennessee's recovery to reflect the exclusion of prepayments. New England Customer Group (New England) argues that in light of the exclusion of prepayments, the Commission must adjust Tennessee's cost allocation formula. New England contends that the elimination of prepayments is significant because it reduces the overall level of costs to be recovered from Tennessee's customers, changes the 1/3-2/3

---

[12] *See Natural Gas Pipeline Co. of America*, 43 FERC ¶ 61,194 (1988); *El Paso Natural Gas Co.*, 42 FERC ¶ 61,024 (1988).

[13] See Statement of Policy and Interpretative Rule [*FERC Statutes and Regulations* ¶ 30,637 (1985)]; and Proposed Policy Statement on Recovery of Take-or-Pay Buy-Out and Buy-Down Costs by Interstate Natural Gas Pipelines, 38 FERC ¶ 61,230 (1987).

buyout/buydown ratio,[14] and changes the level of costs not allocated to G and GS customers.

In contrast, Tennessee argues that it should be allowed recovery of prepayments. It notes that in light of the cost cap, any recovery of prepayments simply diminishes the ability of Tennessee to recover other take-or-pay costs. Alternatively, Tennessee requests that if the Commission denies recovery of prepayments as part of the settlement offer, it should clarify that these costs are recoverable in a general rate case.

The Commission affirms its decision to eliminate recovery of prepayments. It does not believe, however, that the cost cap should be reduced to reflect the elimination of prepayments. As mentioned earlier, Order No. 500 does not require a cap on the amount that a pipeline transporting under Part 284 may seek to recover through a fixed take-or-pay charge. If Tennessee elected not to recover prepayments under the proposed recovery mechanism, the entire $750 million would still be available for recovery of buyout and buydown costs. In response to Tennessee's concern, the Commission clarifies that these prepayment costs may be included in a general rate case.

E. Tennessee Cost Allocation Proposal

Under the settlement proposal approved by the Commission on February 8, 1988, Tennessee would absorb 50 percent of its take-or-pay costs and its customers would be billed the other 50 percent, up to a ceiling of $650 million. In the order issued February 8, 1988, the Commission approved Tennessee's proposed method of allocating among its customers its buyout and buydown costs, although the method did not conform to the purchase deficiency method set forth in Order No. 500. Tennessee's customers' 50 percent share would be recovered through

---

[14] Tennessee allocated recovery of all prepayment costs to the 1/3 buyout portion of its cost allocation proposal.

a fixed take-or-pay surcharge to be based on two separate allocation methods, each of which is weighted differently.

In determining each customer's surcharge, the figures calculated under the two separate allocation mechanisms are combined. One mechanism is used to determine take-or-pay buyout costs, which is to account for one-third of the surcharge. This buyout formula embodies a three-prong procedure which determines costs based on the total of: (1) the customer's annual quantity limitation (AQL), (2) the customer's deficiency in purchases below 82 percent of its AQL during the period January 1, 1981 through December 31, 1985,[15] and (3) the customer's historical purchase deficiency, in this case the amount by which the customer's average day purchases during the years 1983-1985 fell short of its purchases druing the years 1981-1982.

A second allocation mechanism is used to determine the buydown, or contract reformation costs, which is to account for two-thirds of the surcharge. It is based on each customer's AQL as of January 1, 1986. The one-third buyout formula applies only to Rate Schedule CD customers, while the two-thirds buydown formula applies to Rate Schedule G and GS customers as well as CD customers. The consolidation of these two allocation formulas results in the percentage billed each customer.

Many of the petitioners argue that the surcharge allocation methodology is a fundamental and significant departure from Order No. 500 and that the evidence of record is insufficient to permit such a deviation from the principles established there. They request that Tennessee be required to adopt a purchase deficiency allocation methodology that is wholly consistent with the Order No. 500 guidelines at Section 2.104. We agree with these petitioners for the reasons discussed below. Since Order No.

[15] Tennessee's weighted average take-or-pay level under its gas purchase contracts is 82 percent.

500 was issued August 7, 1987, the Commission has approved four proposals, apart from Tennessee's, filed by pipelines to allocate their take-or-pay costs under the equitable sharing mechanism established in Order No. 500.[16] They all allocate costs based on the purchase deficiency allocation methodology established in Order No. 500. Based on that experience the Commission now recognizes that a deviation from the purchase deficiency methodology set out in Order No. 500 will not produce just and reasonable results. Moreover, in the Commission's view it is important to maintain consistency among pipelines in the manner in which take-or-pay buyout and buydown costs are allocated.

1. *The Use of Annual Quantity Limitations to Determine Take-Or-Pay Costs.*

Many petitioners argue that the sole method for determining take-or-pay liability should be based on the customer's purchase deficiencies. They point out that Order No. 500 expressly provided for the use of purchase deficiencies to allocate take-or-pay settlement costs, and that the Commission has rejected other proposals because they failed to do so. Numerous petitioners complain that the Commission cited no circumstances peculiar to the Tennessee system that warrant any deviation from the allocation methodology adopted in Order No. 500. They urge that, as a result, the Commission has deviated without a rational basis supported by substantial evidence not only from the requirements of Order No. 500 but from the other Commission decisions under Order No. 500 issued subsequently.

---

[16] *United Gas Pipe Line Company*, 41 FERC ¶ 61,381 (1987), *reh'g denied*, 42 FERC ¶ 61,197 (1988) (*United*); *Transcontinental Gas Pipe Line Corp.*, 42 FERC ¶ 61,407 (1988) (*Transco*); *Southern Natural Gas Company*, 43 FERC ¶ 61,186 (1988) (*Southern*); and *Natural Gas Pipeline Company*, 43 FERC ¶ 61,194 (1988) (*Natural*).

In Order No. 500, the Commission adopted Section 2.104 which specifies the methodology to be used for the allocation of buyout and buydown costs. Specifically, it provides that:

> Fixed charges must be [allocated] based on each customer's cumulative deficiency in purchases in recent years (during which the current take-or-pay liabilities of the pipelines were incurred) measured in relation to that customer's purchases during a representative period during which take-or-pay liabilities were not incurred. The allocation formula employed must incorporate the following guidelines:
>
> (1) A representative base period must be selected. The base period must reflect a representative level of purchases by the pipeline's firm customers during a period preceding the onset of changed conditions which resulted in reduced purchases and growth of the take-or-pay problem.
>
> (2) Firm purchases by each customer during the base year under firm rate schedules or contracts for firm service must be determined.
>
> (3) Firm sales purchase deficiency volumes for each subsequent year must be determined.
>
> (4) A fixed charge based on each customer's cumulative deficiencies as compared to total cumulative deficiencies must be derived.[17]

Thus, consistent with the guidelines, the fixed surcharge is to be derived from a simple and straightforward methodology in which a customer's cumulative purchase deficiencies in recent years when purchase levels dropped is compared to its purchases during the period before it reduced gas purchases. As several petitioners point out, Tennessee's proposal allocates the greater portion of the take-or-pay costs on the basis of AQL's. New England

[17] Section 2.104(b).

notes that only the third part of the three-prong formula, which is used to allocate buyout costs, reflects the purchase deficiency methodology of Order No. 500 while the second part of the formula uses deficiencies only as a partial measure.

In approving Tennessee's proposed methodology, the Commission acknowledged that it allocated take-or-pay costs only partly on past purchase deficiencies and partly on annual entitlements. Approval of the formula rested on Tennessee's premise that all of its customers have benefited from the execution of its take-or-pay contracts and the reduced prices and added flexibility resulting from the modification of its gas purchase contracts. Specifically, the Commission concluded that "although this allocation methodology deviates from Order No. 500, which would allocate all costs based on purchase deficiencies, the settlement's allocation factors give recognition to several circumstances that are related to the incurrence of take-or-pay on Tennessee's system and therefore do not appear to be unreasonable." [18]

On rehearing, we find, however, that the allocation factors based on AQL are unreasonable and that compliance with the cost incurrence principles based on past purchase deficiencies, as established in Order No. 500, is required to ensure the reasonable allocation of costs on Tennessee's system. Central Hudson Gas & Electric Corp., Orange & Rockland Utilities, Inc., and others argue that Tennessee's proposal improperly assigns buydown costs to those that continued to purchase at high load factors who did not contribute to Tennessee's take-or-pay exposure. The comments are correct that in this, and other respects, Tennessee's proposal does unreasonably allocate costs to customers that did not necessarily contribute to Tennessee's take-or-pay exposure.

As New England points out, AQL is a measure of contract entitlement and, as a result, does not reflect ac-

[18] 42 FERC at p. 61,629.

tual purchase patterns. The cost incurrence principle established in Order No. 500 requires that customers which failed to purchase gas from Tennessee be required to pay the take-or-pay costs incurred today that are associated with their past deficiencies in purchases. Thus, in Order No. 500, the Commission determined that allocating these costs on the basis of past purchase deficiencies links more closely current cost incurrence with cost causation. On rehearing, we must conclude that Tennessee fails to establish that use of AQL is a reasonable basis for assessing a customer's liability.

In *Southern* the Commission specifically rejected a method based on contract demand which, like AQL, is a measure of contract entitlement rather than purchase deficiency. As we found there, figures derived under such bases fail to take into account purchasing practices and thus cannot be as reasonable a measure of a customer's responsibility for take-or-pay costs as purchase deficiency figures.

2. Exemption of G and GS Customers from Buyout Costs.

On rehearing, Columbia Gas Transmission Company (Columbia), New England, and others argue that Tennessee's G and GS customers should not be exempt from liability under the buyout allocation formula which accounts for one-third of the surcharge. They contend that the Commission erred in its justification for approving such a preference for G and GS customers and that such preferences are inconsistent with Order No. 500.

In approving Tennessee's proposed exclusion, the Commission relied on Tennessee's premise to exclude these customers from buyout costs because they were unable to switch from Tennessee to alternate suppliers. New England, however, argues that CD customers, which were not excluded and are the only customers to be assessed, also may remain solely dependent upon Tennessee

for the Tennessee-served portions of its market area despite its access to a gas supply from another pipeline.

The Commission agrees that the record fails to support the distinction between Tennessee's G and GS customers and Tennessee's CD customers relied on by Tennessee to permit their different treatment in the allocation formula for buyout costs. A CD customer that is required to purchase from Tennessee would be allocated buyout costs, whereas G and GS customers under the same circumstances would not. Moreover, under Tennessee's tariff, a customer that has storage facilities must purchase under the CD rate schedule, rather than the G rate schedule. A CD customer can be a full requirements customer.

Tennessee should not exempt its G and GS customers as a class from bearing their share of any of Tennessee's take-or-pay costs. One of the underlying premises of our policies in Order No. 500 is that there should be the broadest reasonable sharing of take-or-pay costs among all segments of the industry. Thus, in Order No. 500, the Commission held that a reasonable basis existed for charging all customers served by a pipeline a share of take-or-pay costs, whether firm, interruptible, sales, small volume, or transportation customers. Recovery of these costs from small volume customers was held to be warranted because such customers, through their purchase deficiencies, "have contributed to pipeline take-or-pay problems" and "all classes of customers should share in the cost of solving the take-or-pay problem." [19] While the Commission in Order No. 500 found that it would be appropriate to charge all customers it did not find that pipelines must do so, for example, leaving to the pipeline the discretion whether to charge transportation customers.[20] In this instance, under the part of Tennessee's al-

---

[19] *FERC Statutes and Regulations* at pp. 30,788-90.

[20] Pipelines have the option to absorb anywhere between 25 percent and 50 percent of the take-or-pay costs. If they choose to

location which we now find acceptable, Tennessee has included the small volume customers. Inclusion of the G and GS customers in the buyout methodology, however, will probably not have a significant impact on such customers of Tennessee. To the extent that they are full requirements customers, they should not have significant purchase deficiencies.

3. One-third/Two-third Split Between Take-Or-Pay Buyout and Buydown Costs

Many petitioners question Tennessee's one-third, two-third allocation method. They note that in Order No. 500 and other settlements the Commission made no distinction between take-or-pay buyout and buydown costs. Therefore, they argue that it is improper to allocate one-third of a customer's liability to take-or-pay buyout costs and two-thirds to buydown, or contract reformation, costs. Petitioners also argue that there is no evidence in the record to support this ⅓-⅔ distinction.

Connecticut Natural Gas Corporation (Connecticut) argues that the allocation of two-thirds of Tennessee's take-or-pay costs to contract reformation costs effectively forces existing Tennessee customers to fund the cost of maintaining gas supply for future sales. It argues that this approach reduces a customer's incentive to use its CD conversion rights, since if it exercised those rights, it still would be required to pay a portion of the costs of maintaining a gas supply which it could not use.

In the prior decision approving the settlement, the Commission relied on Tennessee's expectation that one-third of its costs would relate to settlement of take-or pay claims and two-thirds to contract reformation. This was based on Tennessee's figures reflecting the present value of certain gas purchases. However, as the com-

---

absorb less than 50 percent, they will then recover some of their costs as a surcharge on, *e.g.*, transportation.

ments point out, Tennessee admitted that those figures were only speculative and that their break down between buyout and buydown costs is arbitrary. Neither Order No. 500 nor the other Commission decisions has under its terms made a distinction between buyout and buydown costs. Both are incurred by Tennessee to resolve its contract problems. The real significance of weighting these costs in such a manner is to again permit their allocation among Tennessee's customers unequally. While it is sometimes necessary to make arbitrary distinctions, given the serious consequences to Tennessee's customers, an arbitrary division of these costs cannot be permitted here. We will adhere to our decision in Order No. 500 to treat buyout and buydown costs in the same manner.[21]

4. *Conformance with a Straight Purchase Deficiency Method*

The third part of Tennessee's three-prong, buyout allocation formula follows the straight purchase deficiency methodology set forth at Section 2.104 of Order No. 500. Consistent with our findings described above on rehearing, Tennessee is directed to rely on the purchase deficiency methodology reflected in this part of its proposal and the guidelines at Section 2.104 in allocating the take-or-pay costs under the fixed surcharge approved in our decision. We will condition acceptance of Tennessee's proposal to recover its costs under Order No. 500 upon Tennessee submitting complete workpapers and narrative discussions establishing that the allocation methodology for the fixed charge is based on the purchase deficiency method set out at Section 2.104.

---

[21] The Commission in the settlement order also held that use of a predetermined composite allocation factor results in each customer knowing its maximum liability without waiting until costs are incurred to determine the factor to be applied. If only one allocation method, i.e., past purchase deficiencies, is used, however, weighting of the method is not an issue since it will account for all the customer's take-or-pay cost obligation. All the costs are put in the same pot and treated equally.

Section 2.104 requires that the charge be based on each customer's cumulative deficiency in purchases in recent years measured in relation to that customer's purchases during a representative period during which take-or-pay liabilities were not incurred. The base period must reflect the period preceding the onset of changed conditions which resulted in reduced purchases. Under the Tennessee proposal, a customer's purchase deficiency reflects the amount by which the customer's average day purchases during the years 1983-1985 fell short of its purchases during the years 1981-1982.

New England argues that purchase deficiencies should be calculated for the years 1982-1986, not 1981-1985. It further asserts that the base period should encompass only 1981 since that was the first full year after curtailment on Tennessee's system and the last year before the impact of the supply/demand imbalance that began in 1982. The record, however, indicates that it was not until 1983 that Tennessee experienced the primary drop in sales. In the initial decision in this proceeding, the ALJ found that although Tennessee's management began responding to excess deliveries of gas in 1982, Tennessee's sales in 1982 were sufficient to avoid take-or-pay exposure that year.[22] Tennessee's actions to correct the problem of excess deliverability were fully undertaken in 1983 and not before. Thus, 1981-1982 qualifies as an appropriate base period under Section 2.104.

As for 1986, the Commission agrees that it should be included in the period in which Tennessee's cumulative deficiencies are calculated for measurement against the base period. At the time Tennessee initiated this general rate increase proceeding on June 6, 1986, 1985 was the most recent year for its calculations. By extending the period to 1986, Tennessee will be able to include additional costs that more accurately reflect its purchase deficiencies consistent with Section 2.104.

---

[22] 42 FERC at p. 65,079.

American Paper Institute raises the question whether the Commission considered the possibility that certain of the customer purchases during the 1981-1982 base period included any interruptible sales made by Tennessee. It states that this finding is critical because Tennessee's take-or-pay costs were not caused by its direct and indirect interruptible sales customers. New England further argues that, in calculating purchase deficiencies, Tennessee's customers should receive take-or-pay relief for released gas, since Tennessee receivd take-or-pay relief for those purchases. In *Natural*, the pipeline included in its purchase calculations released gas, which it defined as relief gas. We concluded that reflecting volumes of relief gas in allocating costs would provide an unwarranted double benefit. Customers already have benefited from lower gas costs in the past as a result of these purchases. Consistent with our findings there, Tennessee will be required to exclude relief gas from its purchase calculations submitted in its workpapers. In approving the Order No. 500 proposal in *United*, interruptible sales also were required to be excluded from the calculation of the fixed charge. Accordingly, Tennessee will be required to exclude them from its purchase calculations reflected in its workpapers.[23]

5. *Transportation Customers; Retroactive Ratemaking*

The Indiana Public Service Commission argues that a portion of Tennessee's take-or-pay buyout and buydown

---

[23] North Penn Gas Company (North Penn) argues that no take-or-pay charge should be imposed on it for costs associated with its only large wholesale customer, Corning Gas Corporation (Corning). Corning switched to another Tennessee customer as its supplier and, North Penn argues, the take-or-pay surcharge should be imposed on the new supplier. In an order issued contemporaneously in Docket No. TA88-1-27-001 *et al.*, the Commission has decided to afford North Penn certain relief with respect to Corning's switch in connection with a direct billing proposal. The relief granted there obviates the need to consider North Penn's requests in this docket.

costs should be allocated to Tennessee's transportation customers. It argues that a substantial portion of transportation customers received firm sales service from LDCs, and that service was supported by the LDC's purchase of firm sales service from Tennessee. However, by converting from firm sales to firm transportation, these customers played a large part in contributing to Tennessee's take-or-pay problems. Indiana further states that, absent direction by the Commission to the contrary, current state passthrough mechanisms may allow these end-users that converted to firm transportation to avoid any collection of take-or-pay costs.

As a general proposition, the Commission agrees that all customers, including transportation customers, should share in paying a pipeline's take-or-pay buyout and buydown costs. However, under the policies of Order No. 500 a pipeline is not required to allocate some of these costs to transportation customers if it can resolve its take-or-pay problems without doing so. This is consistent with the Commission's general desire to avoid unnecessary disincentives to transportation. With respect to a state commission's ability to allocate an LDC's share of a pipeline's take-or-pay costs, state commissions are free to make whatever allocation decisions are permitted within the constraints of applicable federal [24] and state law. Thus, nothing in the Commission's Order No. 500 policies is intended to limit a state's ability to decide issues concerning an LDC's passthrough of the fixed take-or-pay charge determined here.

Several parties also allege that the allocation of take-or-pay costs cannot be based on customers' past purchase decisions and that to do so constitutes retroactive ratemaking. Contrary to the Commission's statement in the February 8, 1988 order, these parties argue that Order

---

[24] *See, e.g., Nantahala Power & Light Company v. Thornburg*, 576 U.S. 953 (1986); and *Kentucky West Virginia Gas v. Pa. Public Utility Comm'n*, 837 F.2d 600 (3rd. Cir. 1988).

No. 380 did not provide adequate advance notice that customers might be liable for these costs.

Both of these issues were discussed in Order No. 500. In that order, as well as in the prior order in this case, the Commission held that take-or-pay recovery under the Commission policy is not a retroactive rate adjustment of the type precluded by the filed rate doctrine. Rather, the issue is the proper method to allocate current take-or-pay expenses. Costs that a pipeline will pay to buy out take-or-pay exposure, reform contracts, or reserve future deliverability are a current expense. These costs are merely being allocated on the basis of past purchase deficiencies, a methodology that links more closely current cost incurrence with cost causation. That this methodology relies on historical purchase data does not turn it into retroactive ratemaking.

F. Passthrough By Downstream Pipeline Customers

Columbia Gas Transmission Corporation and certain other parties contend that the Commission should have approved the settlement provision allowing the downstream passthrough of Tennessee's take-or-pay costs without further challenge. They argue that eliminating this passthrough will require them to defend Tennessee's take-or-pay passthrough mechanism in their own rate proceedings. Columbia argues that this could unlawfully "squeeze" the pipeline customer if cost imposition is mandated on the upstream side but costs are denied on the downstream side.

With respect to the downstream passthrough issue, Alabama-Tennessee argues that, to the extent fixed take-or-pay charges are billed to downstream pipelines, the 50/50 cost sharing requirement in Order No. 500 should not be applied to such pipelines. Rather, the downstream pipeline should be permitted the opportunity to recover from its customers all of the costs which it is billed by its pipeline suppliers. Northern Illinois Gas Company urges

the Commission to deny as-billed treatment of direct billed costs to downstream pipelines that do not transport under Part 284 of the regulations.

The Commission affirms its decision to eliminate the guaranteed passthrough provision from Tennessee's settlement proposal. The purchasing practices of downstream pipelines are appropriately subject to prudence challenges in connection wiht the downstream pipelines' incurrence of take-or-pay charges from their upstream pipeline suppliers.

The Commission clarifies, however, that contrary to the apparent assumption of Alabama-Tennessee, the downstream pipeline would be permitted the opportunity to recover from its customers all of the costs which it is billed by its pipeline suppliers.[25] Also, contrary to the argument of Northern Illinois Gas Company, the requirement that a pipeline must be a Part 284 transporter to recover take-or-pay costs outside of the commodity rate only applies to the upstream pipeline company's recovery of its take-or-pay costs paid to producers. A downstream pipeline company is required to flow through costs to its customers on the same basis as they are incurred from the upstream pipeline, regardless of the pipeline's status as an open-access transporter.

G. Section 5 Contract Reformation

Under the approved settlement, Tennessee agrees that it will continue to pursue section 5 relief from the Commission in the context of the current proceeding in Order No. 500, and, if necessary, any appropriate proceeding established by the Commission in the future. Numerous parties on rehearing urge the Commission to exercise its authority under section 5 of the Natural Gas Act (NGA). These parties request that the Commission reform Ten-

[25] *See Mississippi River Transmission Corp.*, 42 FERC ¶ 61,244 (1988).

nessee's gas contracts either simultaneously with or before taking final action on the settlement proposal.

CNG Transmission Corporation (CNG) contends that the record in this proceeding is ripe for decision and that further deferral of the section 5 issue will result in irreparable harm, i.e., consumers will be forced to pay for contract reformation costs that would be unnecessary if the Commission exercised its section 5 authority. Central Hudson Gas and Electric Corporation (Central Hudson) agrees with CNG and states that the Commission is forcing customers to pay now, through a fixed take-or-pay charge, contract reformation costs which may be completely unnecessary due to subsequent section 5 relief.

New England contends that Tennessee's promise to continue to pursue section 5 relief is so vague as to promise nothing at all. New England continues to request Commission approval of its competing proposal filed in this proceeding, which New England believes provides a practical solution for section 5 relief.[26]

In New England's view, a proper cost recovery mechanism could be implemented subject to the express understanding that the cap would be reduced and refunds ordered after contract reformation efforts are completed. Even if the Commission does not accept New England's proposal, New England and others emphasize that the Commission must clarify on rehearing that any collections made by Tennessee are subject to refund pending the Commission's resolution of the section 5 issue.

---

[26] In addition to setting forth criteria for determining which of Tennessee's contracts are unlawful, New England's proposal: (a) requires Tennessee to submit a list of contracts which meet the stated criteria (b) calls for a Commission order requiring the parties to enter into negotiations and to produce revised contracts meeting certain criteria, and (c) provides that contracts not meeting the criteria within a certain time shall be modified by the Commission to declare the take-or-pay provisions null and void.

The Commission denies rehearing on this issue. Approval of an appropriate cost passthrough mechanism should not be delayed pending the Commission's consideration of these same issues in the Order No. 500 proceeding. Deferral of a final Commission decision in this case could slow the contract reformation process. As a result, take-or-pay liabilities that could be reduced through reformation will continue to increase contrary to the objective of Order No. 500 to resolve this problem quickly and effectively.

In response to the concern raised on rehearing, the Commission clarifies that Article II Section 2 of the settlement agreement itself provides that, in the event the Commission ultimately modifies the terms and conditions of Tennessee's gas purchase contracts, nothing in the terms of the settlement shall preclude any resulting benefits of that action from accruing to Tennessee's customers, including a reduction in the customers' maximum liability under the settlement for take-or-pay costs. Finally, to the extent any party is of the view that the amount of costs they would pay under a decision based on the record here would be less than under the proposal adopted here, that party is free to choose to continue litigating this case.

H. Gas Inventory Charge

The approved settlement proposal contains a provision stating that "it is in the mutual interest of Tennessee and its customers" to put into place a mechanism by which Tennessee would allocate and recover its ongoing costs of maintaining gas supplies for its customers. The settlement therefore calls for continued negotiations between Tennessee and its customers to develop a gas inventory charge. In response to staff's comments, Tennessee clarified that take-or-pay costs (including contract reformation costs) would only be recovered either through the settlement's passthrough mechanism or a gas inventory charge.

Connecticut requests further clarification of this issue. It contends that the Commission ignores the key fact that the settlement contains no evidence to determine which costs are to be recovered through contract reformation, which costs are to be recovered through a gas inventory charge, and how those two costs differ. Connecticut further states that the Commission's inadequate treatment in this proceeding of the interrelationship between contract reformation costs and a gas inventory charge parallels the Commission's deficient treatment of the producer inventory charge proposed by Tennessee in Docket No. TA88-1-9-000.[27]

The Commission denies rehearing on this issue. There is no opportunity for Tennessee to double recover these take-or-pay costs. As noted by the Commission in the prior order, Article I, Section 1a of the approved settlement agreement defines take-or-pay costs eligible for fixed charge recovery as excluding any costs reflected in the gas inventory charge. Likewise, in Docket No. TA88-1-9-000, the Commission made clear that Tennessee cannot double recover the take-or-pay costs directly billed pursuant to the settlement agreement. The Commission stated that the producer inventory charges relate to current and future gas purchases as opposed to expenses incurred to buy out accrued liabilities or to reform existing contracts, and as such, the charges would not be recoverable under the terms of the settlement.

I. Standby Sales Services

In the February 8, 1988 order, the Commission declined to approve Tennessee's proposed standby sales service. The Commission stated that although it favored Ten-

[27] Docket No. TA88-1-9-000 involves a Tennessee PGA filing which includes a producer inventory charge. On March 25, 1988, the Commission issued an order denying rehearing of a suspension order issued in this proceeding on December 31, 1987. 41 FERC ¶ 61,369 (1987), *reh'g denied*, 42 FERC ¶ 61,368 (1988).

nessee's efforts to establish a standby sales service, the standby rate under the settlement proposal was not properly designed. The Commission also rejected Tennessee's request for pre-granted abandonment authorization to terminate the service as of February 1, 1989. The Commission directed Tennessee, as a condition to approval of the settlement proposal, to file within 30 days an application for certificate authorization to provide this service.

On rehearing, Tennessee states that the Commission effectively required it to provide standby service for an indefinite period of time. Tennessee adds that Order No. 500 does not require standby service, and that the Commission has singled out Tennessee to provide unlimited standby service while no other pipeline has been required to do so in submitting settlements under Order No. 500. In Tennessee's view, it has been ordered to offer a service which it is not "able and willing" to provide, contrary to section 7(e) of the NGA.

Tennessee and several of its customers also object to the Commission's requirement in the order that Tennessee separately file for a certificate to provide standby service. They argue that this is not a new service and therefore does not require separate certification.

Tennessee is correct that providing standby service is not required by Order No. 500 nor a necessary condition to the passthrough of take-or-pay costs. The Commission merely imposed this condition because Tennessee itself had proposed to begin providing this service as part of the settlement agreement, and this provision may have influenced parties' decisions to consent to the agreement. Thus, if Tennessee's proposal had not included standby service as part of the package, the Commission would not have spoken to the issue. Having proposed to provide the service, the Commission will require that it be implemented in a manner that is consistent with the NGA—that is, under appropriate certificate authority and just and reasonable rates.

Likewise, the Commission confirms that the standby sales proposal represents a change in pipeline service, and that Tennessee must file for appropriate certificate authorization. New certificate authorization is required because Tennessee will be offering its customers a new service. Customers will be able to swing between sales and transportation on a daily basis. This is a fundamental change from the existing sales service in that it changes the nature of the service and thus, requires new certificate authorization.[28] Moreover, standby service, as noted in the prior order, requires a significantly different rate structure to avoid cross-subsidization and proper recovery of costs.

J. Other Related Issues

1. PGA Dockets

The Commission allowed Tennessee's PGA Docket Nos. TA84-2-9-007 and TA85-1-9-004 to be included in the approved settlement. Associated Gas Distributors (AGD) argues that the Commission is required to decide these dockets on their merits outside of the settlement because the two cases were on remand to the Commission from the court of appeals. AGD argues further that to include these two dockets in the February 8, 1988 order deprives the parties of an opportunity to contest the issues raised in those cases.

The Commission disagrees. The issues involved in the two PGA dockets are subsumed within the issues resolved in Tennessee's settlement agreement. The costs at issue in all three proceedings arise out of the same contracts and practices of Tennessee. Furthermore, as stated in the prior order, the Commission will continue these PGA dockets for parties not consenting to the settlement.

---

[28] *See El Paso Natural Gas Company*, Order Granting in Part and Denying in Part Rehearing, 43 FERC ¶ 61,327 (Docket No. RP88-44-000 *et al.*)

2. Tennessee's Prior Take-or-Pay Funding Settlement

In the prior order, the Commission agreed with Tennessee that the April 11, 1986 settlement agreement in Docket No. RP85-178-000 could be terminated. The prior settlement included a provision for direct billing of the cost-of-service effect of prepayments and take-or-pay buyout costs. The Commission determined that to allow continuation of the prior settlement simultaneously with the new settlement would be unjust, unreasonable, unduly discriminatory and preferential.

Certain parties argue that the Commission cannot lawfully abrogate the prior settlement because the Commission did not find that the prior settlement was no longer just and reasonable. Equitable adds that, even if the Commission did find its take-or-pay liability under the prior settlement to be unjust and unreasonable, the remedy under NGA section 5 is to lower its take-or-pay liabilities, not to raise them. Equitable requests that the Commission approve Tennessee's settlement in this case only under the condition that it not disturb the ceiling on Equitable's and other customers' take-or-pay obligations under the prior settlement. These parties argue that terminating the prior settlement unjustly shifts take-or-pay costs primarily from Columbia to other Tennessee customers.

Tennessee asks that if the Commission disapproves fixed charge recovery for prepayments under the settlement agreement in this docket, that it allow the recovery procedures of the April 11 settlement to continue with respect to these prepayments.

The Commission affirms its section 5 finding as discussed in the prior order and denies rehearing on this issue. To allow continuation of the earlier settlement in Docket No. RP85-178-000 simultaneously with the settlement approved in this docket would be unduly discrimina-

tory and preferential. In the Commission's view, equity requires that the cost allocation methodology used in the earlier settlement not be maintained for the much greater costs at issue in this case, and to allow some customers to have their costs determined under that prior settlement would be unduly discriminatory. Nor is there any bar to permit Tennessee to bill Equitable for some costs under this proposal than Equitable would pay under the prior settlement. Section 5 only prohibits the Commission from directing rate increases; it does not preclude the pipeline itself from filing to effect such rate increases as in the case here.

3. Storage

The settlement order rejected Public Service Electric and Gas Company's request that the Commission require Tennessee, as part of the settlement, to permit storage of gas from any source up to 100 percent of the customer's maximum storage quantity. In doing so, the Commission noted that Tennessee had filed in Docket No. CP87-103-000 to open one-third of its contract storage to third party gas. The Commission found that proceeding to be the more appropriate forum to address the issue of third party storage.

On rehearing, the Customer Group [29] argues that the settlement proceeding is the proper forum for deciding this issue, and that without this requirement, Tennessee's customers who must rely on storage to serve firm winter requirements will effectively be forced to fill that storage with Tennessee's gas under what amounts to a minimum purchase obligation.

The Commission continues to believe that Docket No. CP87-103-000 is a more appropriate case in which to

---

[29] Consolidated Edison Company of New York, Inc., The Brooklyn Union Gas Company, Long Island Lighting Company and Public Service Electric and Gas Company.

determine storage for third parties. Storage is, at best, ancillary to the determination of an appropriate take-or-pay passthrough mechanism.

4. Sunset Date

In its proposed settlement, Tennessee would have had until December 31, 1989, to settle take-or-pay claims or reform contracts in order for those payments to be eligible for fixed charge recovery. The settlement order modified that date to December 31, 1988. Tennessee argues that this time limit is too short and that requiring Tennessee to complete its settlements by that date enhances a producer's bargaining position and could therefore result in higher take-or-pay settlement costs.

The Commission is not persuaded that the December 31, 1988, date for settling take-or-pay contracts should be extended. Tennessee has had ample time to begin these negotiations. As stated by the Commission when adopting Order No. 500, it is desirable that the take-or-pay deterrent to competitive natural gas markets and services be eliminated as quickly as possible. By shortening this time limit, both Tennessee and its producers will have an incentive to reach a settlement quickly.

5. Reporting Requirements

Ordering Paragraph (B) of the prior Commission order directs Tennessee to submit copies of each take-or-pay settlement agreement that it enters into, together with an explanation of what each settlement entails. Tennessee asks that this requirement be deleted, arguing that it is unnecessary since Tennessee's efforts to settle take-or-pay claims and to reform contracts are insulated from challenge. If competitors or producers with whom it is still negotiating have access to these settlements, Tennessee argues that it will be put at a competitive or negotiating disadvantage. Tennessee alternatively requests that if the Commission does require this information, the

Commission clarify that the information will be kept confidential.

CNG and Joint Intervenors claim that the settlement should have contained better procedures for verifying Tennessee's claimed cost recovery. They argue that absent a procedure for verification of future buyouts and buydowns, customers will have no assurance that Tennessee will not bill directly prepayments or affiliate costs.

The Commission's regulations, 18 C.F.R. § 388.110, provide a procedure for companies to request confidential treatment of documents that must be filed with the Commission and Tennessee is free to invoke those regulations for the documents it must file. This information is necessary for the Commission to verify matters related to the approved settlement agreement, including Tennessee's absorption of 50 percent of these take-or-pay costs. Likewise, Commission review of this data should satisfy the concerns of CNG and Joint Intervenors regarding procedures to verify Tennessee's cost recovery.

6. *Tariff Sheets Modification of Settlement Language*

Ordering Paragraph (D) of the prior order directs Tennessee to file within 15 days revised tariff sheets "in accordance with the terms of the settlement, this order, and the Commission's Rules and Regulations." Tennessee argues that this requirement is unnecessary and conflicts with the terms of the settlement. The settlement sets forth two types of revised tariff sheets that are to be filed by Tennessee. They are contained in Appendices B and C of the October 14 settlement. The Appendix B tariff sheets will set forth the take-or-pay surcharges for each customer at the time Tennessee commences direct billing of take-or-pay and contract reformation costs. Billing cannot occur, however, until the settlement becomes effective. This will be after the Commission's settlement order becomes final and no longer subject to rehearing,

in accord with Article V of the October 14 Stipulation. In addition, Article I, Section 7 of the Tennessee proposal provides that the Appendix B tariff sheets are only to be filed on each May 31 and December 1, and no earlier than May 31, 1988. Thus, Tennessee argues that no purpose would be served by filing the Appendix B tariff sheets within 15 days.

Tennessee also argues that it would be premature to file standby service tariff sheets, since the Commission stated that it would not approve standby service as part of the settlement agreement. Tennessee states that the more efficient course would be to require Tennessee to file *pro forma* tariff sheets as part of its certificate application for standby service.

By notice issued February 23, 1988, the Commission granted an extension of time for compliance with Ordering Paragraphs (C) and (D) of the settlement order until 30 days after the Commission acts on rehearing. This supersedes the requirements of the prior order. The Commission now clarifies that standby service tariff sheets are to be filed in the certificate proceeding and that take-or-pay tariff sheets must be filed within 15 days of the issuance of this rehearing order to reflect the revised cost allocation method.

Under Article I, Section 7 of the settlement agreement, Tennessee's take-or-pay tariff sheets are to become effective without suspension or refund obligation apart from that undertaken is the agreement itself. The Customer Group requests that the Commission modify this provision because Tennessee's tariff sheets could be wrong, could contain a disagreement as to interpretation, or could otherwise be subject to challenge. The Customer Group also questions how these tariff sheets are to be implemented consistent with Article I, Section IV, which permits Tennessee and its customers to negotiate their own payment methods and terms outside of the terms of the settlement.

As the Commission pointed out in the prior order, Tennessee's tariff sheets are only to be made effective "to the

extent consistent with the terms of this stipulation." Also, the Commission sees no inconsistency between Tennessee's take-or-pay tariff sheets and the settlement provision authorizing negotiations of the terms and payment methods of directly billed take-or-pay costs. Tennessee's take-or-pay tariff sheets only set forth the amount of each customer's liability, not the method or timing of the payment of that obligation.

With respect to Tennessee's request for clarification as to whether it is required to file amended provisions of the settlement, the Commission clarifies that it is not necessary for Tennessee to file revisions to the settlement to account for modifications made by the Commission. Any necessary language changes are subsumed within the order approving the settlement, and will be given effect in the tariff sheets filed to comply with these orders.

The Commission orders:

(A) The requests for rehearing filed in this docket are granted in part and denied in part as set forth in the body of this order.

(B) Subject to the modifications, conditions, and clarifications in this order and the order issued February 8, 1988, in this proceeding, the offer of settlement filed by Tennessee, on October 14, 1987, is approved.

(C) Approval of Tennessee's settlement filed October 14, 1987, is also subject to Tennessee's submitting to the Commission, in addition to the reporting obligation set forth in Article I, Section 8 of the Tennessee settlement, details of the costs included in the filing, including copies of each settlement agreement entered into and an explanation of what each settlement entails.

(D) Within 15 days of the issuance of this order, Tennessee shall file tariff sheets reflecting the revised cost allocation methodology adopted in this order, including work papers showing the derivation of allocation factors.

APPENDIX G

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Nos. 88-1385, *et al.*

ASSOCIATED GAS DISTRIBUTORS, *et al.*,
Petitioners

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

PETITION OF THE
FEDERAL ENERGY REGULATORY COMMISSION
FOR REHEARING AND SUGGESTION
FOR REHEARING *EN BANC*

WILLIAM S. SCHERMAN
General Counsel

JEROME M. FEIT
Solicitor

JOEL M. COCKRELL
Attorney

For Respondent
Federal Energy Regulatory
Commission
Washington, D.C. 20426

February 12, 1990

ADDENDUM

CONTENTS

Page

Notes and Sources ....

Chart 1 Impact of Deficiency Allocation ....

Chart 2 Impact of CD-based Allocation ....

Chart 3 Impact of Volumetric Allocation ....

Schedule 1 Comparison of Deficiency and CD Allocations, by Customer ....

Schedule 2 Comparison of Deficiency and Volumetric Allocations, by Customer ....

Notes and Sources

1. The charts and schedules are intended to demonstrate impacts that may result if non-deficiency based allocation methodologies are used. The comparison methodologies chosen—contract demand and volumetric—are two methods often suggested when alternative methodologies are considered.

The contract demand (CD) based allocation method essentially maintains intact the Commission's take-or-pay recovery method, but substitutes a direct bill based on CD factors in place of a direct bill based on deficiency allocation factors. The impacts of this method are shown in Chart 2 and Schedule 1.

The volumetric allocation method assumes that the Commission permits 100 percent of the buyout and buydown costs to be flowed through in a volumetric surcharge across total pipeline throughout. The impacts of this method are shown in Chart 3 and Schedule 2.

2. Charts 1, 2 and 3 represent the division of Tennessee's buyout and buydown costs by customer class, for the indicated allocation methods. Schedules 1 and 2 represent a more detailed comparison of a CD-based approach and a volumetric surcharge approach with the current deficiency-based approach.

Schedules 1 and 2 use the same format. The deficiency allocation factors are compared to the alternative allocation factors. The difference between the factors is then multiplied by Tennessee's total take-or-pay costs to show, on a customer specific basis, the cost shifts that will take place by using an alternative in place of the deficiency-based approach.

3. Although Tennessee's absorption under the volumetric surcharge is shown as zero, Tennessee may in fact absorb some of these costs to the extent that it discounts its transportation rates to counteract the increase in those rates caused by the surcharge.

4. These charts and schedules do not take into account carrying costs which have accrued on Tennessee's take-or-pay balances.

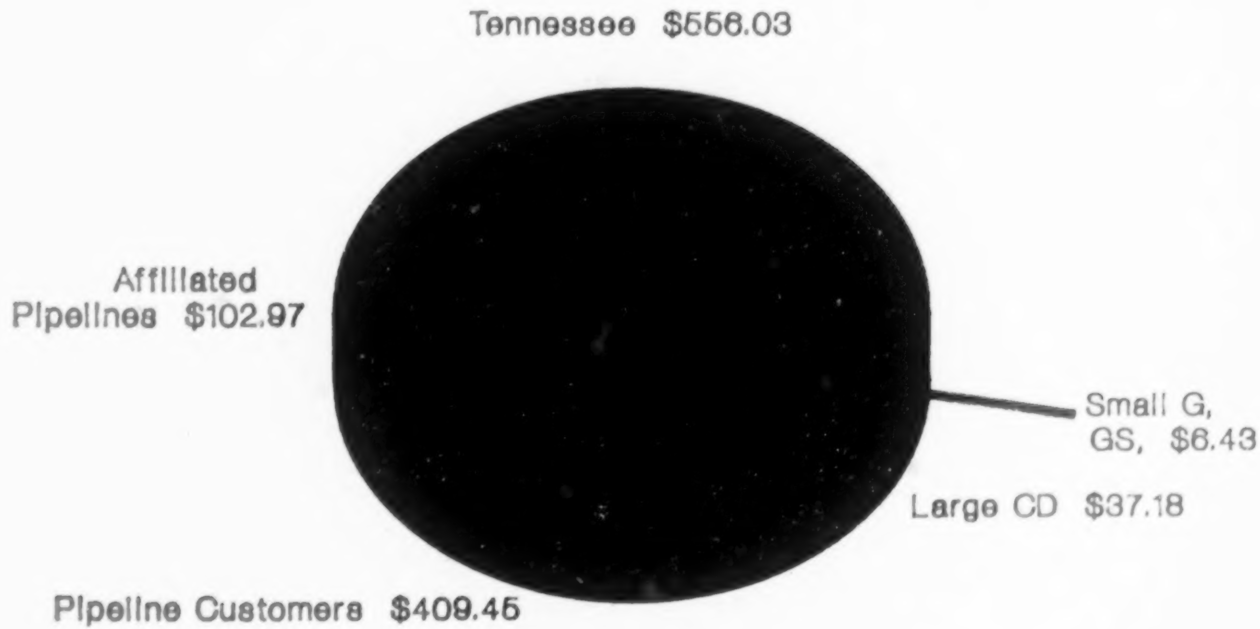
5. The source of the deficiency allocation percentages was Tennessee's compliance filing in Docket No. RP88-191, petition for review pending in *Tennessee Gas Pipeline Company, et al. v. FERC*, D.C. Cir. Nos. 88-1680, *et al.*

6. The source of the CD levels was Tennessee's initial filing in Docket No. RP88-228, Schedule G. Transportation CDs were aggregated with sales CDs for computing each customers total CD.

7. The source of the volumetric information was Tennessee's 1988 Form 2. Transportation was identified by revenue company. Customers may be listed both under sales and transportation headings. For example, Schedule 2 (page 11 of the Addendum) shows that Columbia would pay $190 million less under the sales portion of the volumetric surcharge than under deficiency-based billing. However, Columbia is also a transportation customer of Tennessee. Schedule 2 (page 12 of the Addendum) shows that Columbia would pay $19 million through Tennessee's transportation rates. Thus, based on these scenarios, the net benefit to Columbia of moving from the deficiency-based method to a volumetric method would be about $170 million.

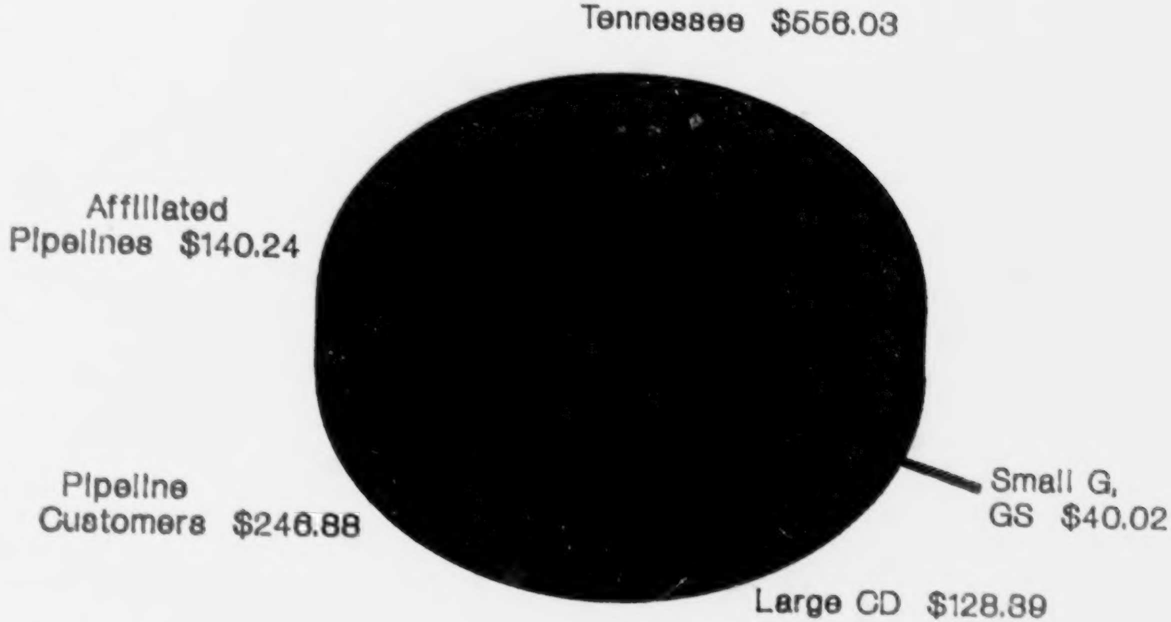
8. These charts and schedules are for illustrative purposes only. While the charts and schedules are believed to be accurate, they should not be relied upon for anything other than their intended purpose: to show the potential impacts of changing from one allocation method to another. They are based on existing historical data, and may not fully reflect Tennessee's current or future sales or transportation profiles.

Tennessee T-O-P Costs
Impact of Deficiency Allocation
(50% Absorption by Tennessee)



(Millions of Dollars)

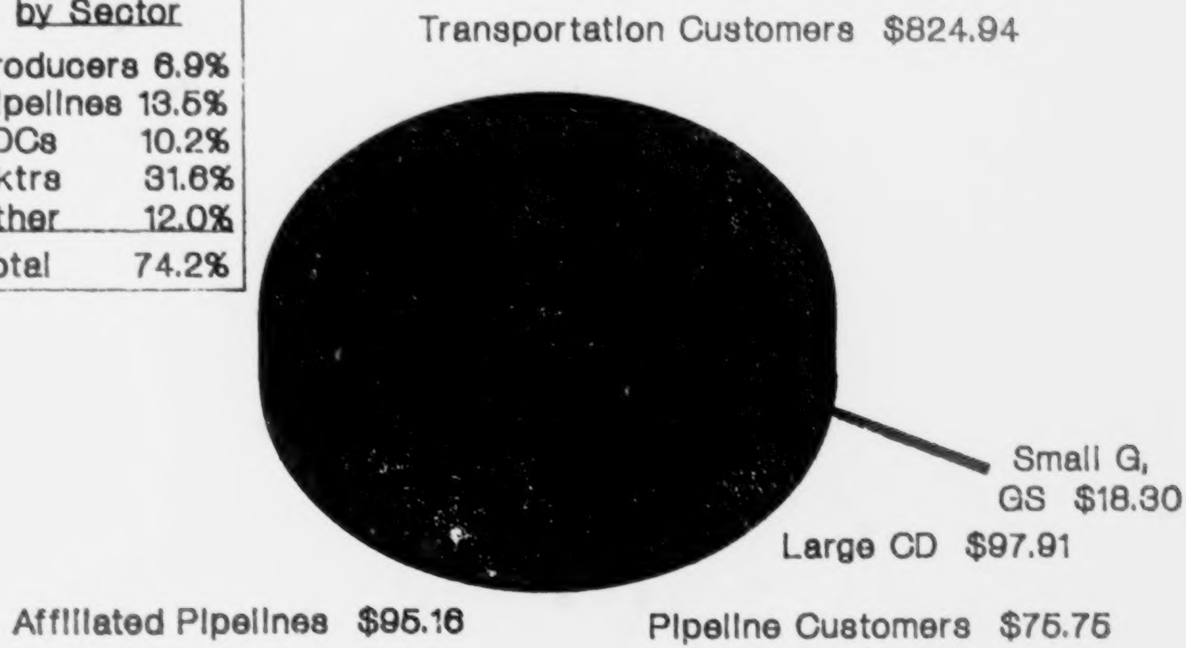
Tennessee T-O-P Costs
Impact of CD Allocation
(50% Absorption by Tennessee)



(Millions of Dollars)

Tennessee T-O-P Costs
Impact of Volumetric Surcharge

Transportation by Sector	
Producers	6.9%
Pipelines	13.5%
LDCs	10.2%
Mktrs	31.6%
Other	12.0%
Total	74.2%



(Millions of Dollars)

Schedule 1

TENNESSEE GAS PIPELINE COMPANY
COMPARISON OF DEFICIENCY AND CD ALLOCATIONS
BY CUSTOMER

Tennessee Take-or-Pay Costs: $1,112,057,152

[1] Customer	[2] Deficiency Allocation Factors	[3] Contract Quantity	[4] CD-based Allocation Factors	[5] Difference (4-2)	[6] Cost Impact of Difference
Tenn. Absorption	50.0000%	0	50.0000%	0.0000%	$0
Small Customers (G, GS)					
Adamsville	0.0000%	6,868	0.0076%	0.0076%	$84,434
Ark. La. Gas	0.0000%	255	0.0003%	0.0003%	$3,135
Ashland	0.0000%	1,805	0.0020%	0.0020%	$22,190
Baldwyn	0.0000%	5,216	0.0058%	0.0058%	$64,124
Batesville	0.0000%	14,591	0.0161%	0.0161%	$179,378
Blackstone Gas	0.0000%	2,954	0.0033%	0.0033%	$36,316
Bolivar	0.0000%	34,343	0.0380%	0.0380%	$422,205
Booneville	0.0000%	16,156	0.0179%	0.0179%	$198,618
Centerville	0.0000%	13,210	0.0146%	0.0146%	$162,401
Central Gas Co	0.0025%	12,770	0.0141%	0.0117%	$129,746
Clarksville	0.0058%	150,623	0.1665%	0.1608%	$1,787,782
Collinwood	0.0000%	3,521	0.0039%	0.0039%	$43,286
Concord Natural	0.0000%	57,651	0.0637%	0.0637%	$708,748
Corinth Utility	0.0000%	32,150	0.0355%	0.0355%	$395,245
Cumberland Gas	0.0526%	5,145	0.0057%	−0.0469%	($521,135)

Delta Natural	0.0101%	86,489	0.0956%	0.0855%	$950,958
Dickson	0.0000%	41,026	0.0454%	0.0454%	$504,364
Elizabeth Nat Gas	0.0000%	1,796	0.0020%	0.0020%	$22,080
Elizabethtown	0.0000%	20,746	0.0229%	0.0229%	$255,047
Entex, Inc.	0.0600%	79,689	0.0881%	0.0281%	$313,000
Forest Hill	0.0000%	1,410	0.0016%	0.0016%	$17,334
Grand Isle	0.0007%	1,697	0.0019%	0.0012%	$13,078
Grayson	0.0029%	6,942	0.0077%	0.0048%	$53,650
Greenbrier	0.0003%	0	0.0000%	—0.0003%	($2,780)
Hardeman-Fayette	0.0000%	11,231	0.0124%	0.0124%	$138,071
Harrisonburg	0.0007%	2,459	0.0027%	0.0021%	$23,002
Hemphill	0.0015%	0	0.0000%	—0.0015%	($16,125)
Henderson	0.0004%	9,335	0.0103%	0.0099%	$110,314
Hohenwald	0.0000%	14,501	0.0160%	0.0160%	$178,272
Holly Springs	0.0098%	16,487	0.0182%	0.0084%	$93,706
Holyoke Gas	0.0165%	96,960	0.1072%	0.0907%	$1,009,071
Honesdale Gas	0.0000%	28,883	0.0319%	0.0319%	$355,081
Humphreys	0.0000%	149,544	0.1653%	0.1653%	$1,838,460
Kountze	0.0060%	0	0.0000%	—0.0060%	($66,167
Lexinton	0.0000%	30,674	0.0339%	0.0339%	$377,099
Linden	0.0000%	3,457	0.0038%	0.0038%	$42,500
Lobelville	0.0000%	1,628	0.0018%	0.0018%	$20,014
Louisiana Gas	0.0005%	643	0.0007%	0.0002%	$2,345
Miss. Valley Gas	0.0000%	502	0.0006%	0.0006%	$6,171
Morehead	0.0056%	14,521	0.0161%	0.0105%	$116,243
Myers, ET (NEOhio)	0.0026%	4,869	0.0054%	0.0028%	$31,501
Nashville (Piedmont	0.2333%	1,560,000	1.7246%	1.4913%	$16,584,412
Nat. Gas and Oil	0.0877%	62,492	0.0691%	—0.0186%	($206,456)
New Albany	0.0000%	27,475	0.0304%	0.0304%	$337,771

[1] Customer	[2] Deficiency Allocation Factors	[3] Contract Quantity	[4] CD-based Allocation Factors	[5] Difference (4-2)	[6] Cost Impact of Difference
Olive Hill	0.0026%	5,861	0.0065%	0.0039%	$43,140
Parsons	0.0020%	8,675	0.0096%	0.0076%	$84,963
Pike Natural	0.0055%	37,618	0.0416%	0.0361%	$401,304
Pontotoc	0.0062%	15,189	0.0168%	0.0106%	$118,339
Portland	0.0000%	17,877	0.0198%	0.0198%	$219,776
Provencal	0.0000%	658	0.0007%	0.0007%	$8,089
Ridgetop	0.0000%	699	0.0008%	0.0008%	$8,593
Ripley	0.0000%	54,389	0.0601%	0.0601%	$668,646
Robeline-Stanley	0.0002%	208	0.0002%	0.0000%	$333
Sam Houston	0.0007%	8,546	0.0094%	0.0087%	$97,278
Savannah	0.0007%	11,189	0.0124%	0.0117%	$130,327
Senatobia	0.0000%	24,405	0.0270%	0.0270%	$300,030
Shuqualak	0.0000%	16,193	0.0179%	0.0179%	$199,073
Springfield	0.0000%	42,061	0.0465%	0.0465%	$517,088
SW Gas	0.0000%	0	0.0000%	0.0000%	$0
Vernon, Dis 1	0.0001%	966	0.0011%	0.0010%	$11,320
Vina Gas Board	0.0000%	389	0.0004%	0.0004%	$4,782
Walnut	0.0000%	2,425	0.0027%	0.0027%	$29,812
Waynesboro	0.0025%	3,642	0.0040%	0.0016%	$17,529
West Tennessee	0.0000%	102,048	0.1128%	0.1128%	$1,254,555
Western Kentucky	0.492%	207,239	0.2291%	0.1799%	$2,000,617
Westfield	0.0080%	62,532	0.0691%	0.0612%	$680,346
Woodville	0.0019%	0	0.0000%	−0.0019%	($20,573)

Large Customers (CD)					
Berkshire Gas	0.0300%	245,604	0.2715%	0.2415%	$2,685,783
Boston Gas	0.4398%	1,156,248	1.2782%	0.8384%	$9,323,822
Brooklyn Union	0.1157%	499,392	0.5521%	0.4364%	$4,852,761
Cabot Corp.	0.1500%	113,460	0.1254%	−0.0245%	($272,678)
Central Hudson	0.0830%	399,516	0.4417%	0.3587%	$3,988,551
Colonial Gas	0.0317%	426,984	0.4720%	0.4404%	$4,897,278
Commonwealth	0.3310%	681,912	0.7539%	0.4229%	$4,702,362
Connecticut Light	0.2122%	543,360	0.6007%	0.3885%	$4,320,159
Connecticut Natural	0.3466%	527,100	0.5827%	0.2362%	$2,626,213
Consolidated Ediso	0.2688%	749,088	0.8281%	0.5593%	$6,219,908
Energynorth	0.0000%	291,756	0.3225%	0.3225%	$3,586,782
Essey County	0.0428%	178,752	0.1976%	0.1549%	$1,722,132
Fitchburg Gas	0.0390%	92,412	0.1022%	0.0632%	$702,390
Long Island Light	0.0177%	124,848	0.1380%	0.1204%	$1,338,575
New York State	0.0883%	342,720	0.3789%	0.2906%	$3,231,931
NW. Alabama	0.0000%	8,448	0.0093%	0.0093%	$103,858
N. Alabama	0.0368%	293,748	0.3247%	0.2879%	$3,202,034
Orange & Rockland	0.4111%	1,052,676	1.1637%	0.7526%	$8,369,692
Penn Gas & Water	0.1268%	700,524	0.7744%	0.6476%	$7,201,994
Penn & So. Gas	0.0143%	152,928	0.1691%	0.1548%	$1,721,038
Phillips TW Gas	0.0275%	62,544	0.0691%	0.0417%	$463,642
Public Service	0.2662%	1,123,632	1.2422%	0.9760%	$10,853,936
Southern Conn	0.2187%	470,052	0.5196%	0.3009%	$3,346,643
Valley Gas	0.0459%	246,180	0.2722%	0.2263%	$2,516,603
Pipeline Customers (CD)					
Alabama-Tennessee	1.1966%	1,590,024	1.7578%	0.5612%	$6,240,517
Columbia Gas	17.6009%	5,123,064	5.6635%	−11.9373%	($132,749,729)

[1] Customer	[2] Deficiency Allocation Factors	[3] Contract Quantity	[4] CD-based Allocation Factors	[5] Difference (4-2)	[6] Cost Impact of Difference
Consolidated Gas	10.6083%	7,574,400	8.3735%	—2.2348%	($24,852,409)
Equitable Gas	1.4341%	781,608	0.8641%	—0.5700%	($6,339,101)
Granite State	0.2876%	1,033,236	1.1422%	0.8546%	$9,504,092
Inland Gas	0.8206%	219,336	0.2425%	—0.5781%	($6,429,074)
National Fuel	3.9090%	3,017,412	3.3357%	—0.5733%	($6,374,938)
N. Penn Gas	0.5581%	378,816	0.4188%	—0.1393%	($1,549,313)
Texas Gas Trans.	0.4044%	364,116	0.4025%	—0.0019%	($20,800)
Affiliated Pipeline Customers (CD)					
East Tennessee	1.8382%	4,010,256	4.4333%	2.5952%	$28,859,896
Midwestern	7.4208%	7,396,800	8.1771%	0.7563%	$8,411,038
Total	100%	45,228,475	100%	0%	($556)

Schedule 2

TENNESSEE GAS PIPELINE COMPANY
COMPARISON OF DEFICIENCY AND VOLUMETRIC
ALLOCATIONS BY CUSTOMER

Tennessee Take-or-Pay Costs: $1,112,057,152

[1] Customer	[2] Deficiency Allocation **Factors**	[3] 1988 Sales & Transportation (MMcf)	[4] Volumetric Allocation Factor	[5] Difference (4-2)	[6] Cost Impact of Difference
TENN. ABSORPTION	50.0000%	————	0.0000%	−50.0000%	($556,028,576)
Small Sales Customers (G, GS)					
ADAMSVILLE	0.0000%	115.879	0.0079%	0.0079%	$87,330
ARK LA GAS	0.0000%	67.228	0.0046%	0.0046%	$50,665
ASHLAND	0.0000%	37.701	0.0026%	0.0026%	$28,413
BALDWYN	0.0000%	104.249	0.0071%	0.0071%	$78,565
BATESVILLE	0.0000%	322.044	0.0218%	0.0218%	$242,701
BLACKSTONE GAS C	0.0000%	65.858	0.0045%	0.0045%	$49,632
BOLIVAR	0.0000%	566.982	0.0384%	0.0384%	$427,293
BOONEVILLE	0.0000%	338.428	0.0229%	0.0229%	$255,049
CENTERVILLE	0.0000%	283.966	0.0192%	0.0192%	$214,005
CENTRAL GAS CO	0.0025%	258.188	0.0175%	0.0150%	$167,332
CLARKSVILLE	0.0058%	779.345	0.0528%	0.0471%	$523,392
COLLINWOOD	0.0000%	16.546	0.0011%	0.0011%	$12,470
CONCORD NATURAL	0.0000%	992.744	0.0673%	0.0673%	$748,159
CORINTH	0.0000%	610.994	0.0414%	0.0414%	$460,462
CUMBERLAND GAS C	0.0526%	98.918	0.0067%	−0.0458%	($509,839)
DELTA NATURAL GAS	0.0101%	1,096.365	0.0743%	0.0642%	$713,933

[1] Customer	[2] Deficiency Allocation Factors	[3] 1988 Sales & Transportation (MMcf)	[4] Volumetric Allocation Factor	[5] Difference (4-2)	[6] Cost Impact of Difference
DICKSON	0.0000%	614.605	0.0417%	0.0417%	$463,183
ELIZABETH NATURAL	0.0000%	23.015	0.0016%	0.0016%	$17,345
ELIZABETHTOWN GA	0.0000%	432.460	0.0293%	0.0293%	$325,914
ENTEX INC	0.0600%	1,179.595	0.0799%	0.0200%	$222,297
FOREST HILL	0.0000%	33.256	0.0023%	0.0023%	$25,063
GRAND ISLE	0.0007%	37.133	0.0025%	0.0018%	$20,200
GRAYSON	0.0029%	138.210	0.0094%	0.0065%	$72,465
GREENBRIAR GAS S	0.0003%	13.397	0.0009%	0.0007%	$7,316
HARDEMAN-FAYETT	0.0000%	176.325	0.0119%	0.0119%	$132,883
HARRISONBURG	0.0007%	54.384	0.0037%	0.0030%	$33,757
HEMPHILL	0.0015%	32.700	0.0022%	0.0008%	$8,519
HENDERSON	0.0004%	182.548	0.0124%	0.0120%	$133,125
HOHENWALD	0.0000%	216.888	0.0147%	0.0147%	$163,453
HOLLY SPRINGS UTI	0.0098%	243.665	0.0165%	0.0067%	$74,651
HOLYOKE GAS & EL	0.0165%	1,796.075	0.1217%	0.1053%	$1,170,638
HONESDALE GAS CO	0.0000%	642.081	0.0435%	0.0435%	$483,890
HUMPREYS COUNT	0.0000%	815,918	0.0553%	0.0553%	$614,898
KOUNTZE	0.0060%	38.635	0.0026%	--0.0033%	($37,051)
LEXINGTON GAS SYS	0.0000%	434.515	0.0294%	0.0294%	$327,462
LINDEN	0.0000%	66.072	0.0045%	•0.0045%	$49,794
LOBELVILLE	0.0000%	33.097	0.0022%	0.0022%	$24,943
LOUISIANA GAS SER	0.0005%	13.736	0.0009%	0.0004%	$4,792
MISSISSIPPI VALLEY	0.0000%	8.693	0.0006%	0.0006%	$6,551
MOREHEAD	0.0056%	287.462	0.0195%	0.0139%	$154,364

MYERS, ET (NE OHIO)	0.0026%	45.273	0.0031%	0.0005%	$5,762
NASHVILLE GAS CO	0.2333%	2,943.857	0.1995%	−0.0337%	($375,302)
NATIONAL GAS & OIL	0.0877%	0.000	0.0000%	−0.0877%	($974,718)
NEW ALBANY	0.0000%	563.023	0.0382%	0.0382%	$424,310
NEW JERSEY NATUR	0.0000%	2.800	0.0002%	0.0002%	$2,110
OLIVE HILL	0.0026%	93.832	0.0064%	0.0038%	$41,801
PARSONS	0.0020%	192.675	0.0131%	0.0111%	$123,520
PIKE NATURAL GAS	0.0055%	403.827	0.0274%	0.0219%	$243,172
PONTOTOC NATURA	0.0062%	372.009	0.0252%	0.0191%	$211,965
PORTLAND	0.0000%	219.302	0.0149%	0.0149%	$165,272
PROVENCAL	0.0000%	11.427	0.0008%	0.0008%	$8,612
RIDGETOP	0.0000%	15.948	0.0011%	0.0011%	$12,019
RIPLEY	0.0000%	273.508	0.0185%	0.0185%	$206,123
ROBELINE-STANLEY	0.0002%	3.819	0.0003%	0.0001%	$654
SAM HOUSTON PUBL	0.0007%	173.509	0.0118%	0.0111%	$122,977
SAVANNAH	0.0007%	247.428	0.0168%	0.0161%	$179,240
SENATOBIA	0.0000%	464.405	0.0315%	0.0315%	$349,988
SHUQUALAK	0.0000%	62.442	0.0042%	0.0042%	$47,058
SOUTHWEST GAS DI	0.0000%	22.897	0.0016%	0.0016%	$17,256
SPRINGFIELD	0.0000%	306.297	0.0208%	0.0208%	$230,834
VERNON DISTRICT N	0.0001%	16.711	0.0011%	0.0011%	$12,038
VINA GAS BOARD O	0.0000%	8.481	0.0006%	0.0006%	$6,392
WALNUT	0.0000%	53.684	0.0036%	0.0036%	$40,458
WAYNESBORO	0.0025%	84.958	0.0058%	0.0033%	$36,781
WEST TENNESSEE P	0.0000%	271.135	0.0184%	0.0184%	$204,335
WESTERN KENTUCK	0.0492%	2,839.816	0.1925%	0.1433%	$1,593,031
WESTFIELD	0.0080%	908.101	0.0615%	0.0536%	$595,961
WOODVILLE	0.0019%	147.300	0.0100%	0.0081%	$90,443

[1] Customer	[2] Deficiency Allocation Factors	[3] 1988 Sales & Transportation (MMcf)	[4] Volumetric Allocation Factor	[5] Difference (4-2)	[6] Cost Impact of Difference
Large Sales Customers (CD)					
BERKSHIRE GAS CO	0.0600%	3,241.466	0.2197%	0.1597%	$1,775,623
BOSTON GAS CO	0.4398%	13,019.809	0.8823%	0.4425%	$4,921,256
BROOKLYN UNION G	0.1157%	6,073.402	0.4116%	0.2959%	$3,290,432
CABOT GAS SUPPLY	0.1500%	1,058.346	0.0717%	−0.0782%	($869,931)
CENTRAL HUDSON G	0.0830%	3,842.762	0.2604%	0.1774%	$1,973,003
COLONIAL NATURAL	0.0317%	7,590.290	0.5144%	0.4827%	$5,368,284
COMMONWEALTH G	0.3310%	8,499.363	0.5760%	0.2450%	$2,724,443
CONNECTICUT LIGHT	0.2122%	5,585.601	0.3785%	0.1663%	$1,849,676
CONNECTICUT NATU	0.3466%	5,493.371	0.3723%	0.0257%	$286,120
CONSOLIDATED EDIS	0.2688%	6,995.998	0.4741%	0.2053%	$2,283,166
ENERGYNORTH INC	0.0000%	4,154.131	0.2815%	0.2815%	$3,130,667
ESSEX COUNTY GAS	0.0428%	2,837.885	0.1923%	0.1496%	$1,663,303
FITCHBURG GAS & E	0.0390%	1,310.985	0.0888%	0.0498%	$554,292
LONG ISLAND LIGHTI	0.0177%	1,474.835	0.0999%	0.0823%	$915,198
NEW YORK STATE EL	0.0883%	4,348.399	0.2947%	0.2064%	$2,295,682
NORTH ALABAMA GA	0.0368%	106.484	0.0072%	−0.0296%	($328,988)
NORTHWEST ALABA	0.0000%	196.385	0.0133%	0.0133%	$148,001
ORANGE AND ROCKL	0.4111%	12,493.697	0.8467%	0.4356%	$4,843,924
PENNSYLVANIA AND	0.0143%	7,528.499	0.5102%	0.4959%	$5,514,658
PENNSYLVANIA GAS	0.1268%	1,577.788	0.1069%	−0.0199%	($221,024)
PHILLIPS T W GAS &	0.0275%	1,360.970	0.0922%	0.0648%	$720,404
PIEDMONT NATURAL	0.0000%	10,843.919	0.7349%	0.7349%	$8,172,274
PUBLIC SERVICE ELE	0.2662%	10,851.953	0.7354%	0.4693%	$5,218,588

SOUTHERN CONNEC	0.2187%	4,893.798	0.3316%	0.1129%	$1,256,031
VALLEY GAS CO	0.0459%	3,268.207	0.2215%	0.1756%	$1,953,132
Pipeline Sales Customers (CD)					
ALABAMA TENNESSEE	1.1966%	9,983.878	0.6766%	−0.5200%	($5,782,753)
COLUMBIA GAS TRA	17.6009%	8,246.310	0.5588%	−17.0420%	($189,516,867)
CONSOLIDATED NAT	10.6083%	28,565.412	1.9358%	−8.6725%	($96,442,684)
EQUITABLE GAS CO	1.4341%	2,101.726	0.1424%	−1.2917%	($14,364,093)
GRANITE STATE GAS	0.2876%	13,743.608	0.9314%	0.6438%	$7,159,282
INLAND GAS CO	0.8206%	3,200.995	0.2169%	−0.6037%	($6,713,184)
NATIONAL FUEL GAS	3.9090%	26,949.043	1.8263%	−2.0827%	($23,160,779)
NORTH PENN GAS C	0.5581%	3,995.575	0.2708%	−0.2873%	($3,195,216)
TEXAS GAS TRANSMI	0.4044%	3,722.788	0.2523%	−0.1521%	($1,691,564)
Affiliated Pipeline Sales Customers (CD)					
EAST TENNESSEE N	1.8382%	41,184.904	2.7910%	0.9529%	$10,596,790
MIDWESTERN GAS T	7.4208%	85,083.572	5.7660%	−1.6548%	($18,402,233)
Other Sales					
MAINLINE INDUSTRIA	0.0000%	1,261.114	0.0855%	0.0855%	$950,410
RETAIL INDUSTRIAL	0.0000%	270.689	0.0183%	0.0183%	$203,999
Producer Transportation Customers					
AMOCO PRODUCTIO	0.0000%	13,498.950	0.9148%	0.9148%	$10,173,178
ARCO OIL & GAS CO	0.0000%	2,789.014	0.1890%	0.1890%	$2,101,877
CHEVRON USA INC	0.0000%	16,509.930	1.1189%	1.1189%	$12,442,334
EXXON CORPORATIO	0.0000%	1,069.596	0.0725%	0.0725%	$806,077
KERR-MCGEE CORP	0.0000%	10,062.467	0.6819%	0.6819%	$7,583,350
MOBIL NATURAL GAS	0.0000%	14,621.057	0.9909%	0.9909%	$11,018,828
MOBIL OIL CORP	0.0000%	27,010.932	1.8305%	1.8305%	$20,356,176

[1] Customer	[2] Deficiency Allocation Factors	[3] 1988 Sales & Transportation (MMcf)	[4] Volumetric Allocation Factor	[5] Difference (4-2)	[6] Cost Impact of Difference
SHELL OFFSHORE IN	0.0000%	1,722.167	0.1167%	0.1167%	$1,297,872
SHELL OIL CO	0.0000%	7,257.748	0.4918%	0.4918%	$5,469,637
SUN OPERATING LIMI	0.0000%	2,003.823	0.1358%	0.1358%	$1,510,136
TENNECO OIL CO	0.0000%	3,997.088	0.2709%	$.2709%	$3,012,315
TOTAL MINATOME C	0.0000%	1,308.654	0.0887%	0.0887%	$986,237
Pipeline Transportation Customers					
ALABAMA-TENNESS	0.0000%	1,327.737	0.0900%	0.0900%	$1,000,619
ANR PIPELINE COMP	0.0000%	5,094.607	0.3453%	0.3453%	$3,839,435
COLUMBIA GAS TRA	0.0000%	25,610.928	1.7356%	1.7356%	$19,301,095
CONSOLIDATED GAS	0.0000%	1,034.427	0.0701%	0.0701%	$779,572
DISTRIGAS OF MASS	0.0000%	1,074.859	0.0728%	0.0728%	$810,043
EAST TENNESSEE N	0.0000%	1,225.314	0.0830%	0.0830%	$923,430
GRANITE STATE GAS	0.0000%	6,733.358	0.4563%	0.4563%	$5,074,443
MID LOUISIANA GAS	0.0000%	1,423.805	0.0965%	0.0965%	$1,073,018
NAT FUEL GAS SUPP	0.0000%	7,053.740	0.4780%	0.4780%	$5,315,891
NATURAL GAS PIPELI	0.0000%	5,095.165	0.3453%	0.3453%	$3,839,856
NORTHERN NATURA	0.0000%	7,294.485	0.4943%	0.4943%	$5,497,323
PANHANDLE EASTER	0.0000%	1,325.524	0.0898%	0.0898%	$998,951
SOUTHERN NATURA	0.0000%	7,238.531	0.4905%	0.4905%	$5,455,155
TEXAS EASTERN TRA	0.0000%	15,859.366	1.0748%	1.0748%	$11,952,052
TEXAS GAS TRANSMI	0.0000%	3,608.065	0.2445%	0.2445%	$2,719,136
TRANSCONTINENTAL	0.0000%	12,918.578	0.8755%	0.8755%	$9,735,793
TRUNKLINE GAS CO	0.0000%	49,446.289	3.3509%	3.3509%	$37,264,074
UNITED GAS PIPE LIN	0.0000%	36,683.567	2.4860%	2.4860%	$27,645,738

LDC Transportation Customers					
BOSTON GAS COMPA	0.0000%	13,346.066	0.9044%	0.9044%	$10,057,960
BRIDGELINE GAS DIS	0.0000%	7,684.512	0.5208%	0.5208%	$5,791,258
BROOKLYN UNION G	0.0000%	10,079.003	0.6830%	0.6830%	$7,595,812
CINCINNATI GAS & EL	0.0000%	3,414.148	0.2314%	0.2314%	$2,572,995
CITIZENS GAS SUPPL	0.0000%	29,142.620	1.9750%	1.9750%	$21,962,675
COLONIAL GAS CO	0.0000%	1,223.101	0.0829%	0.0829%	$921,762
COMMONWEALTH G	0.0000%	2,160.108	0.1464%	0.1464%	$1,627,916
CONNECTICUT LIGHT	0.0000%	6,405.296	0.4341%	0.4341%	$4,827,206
CONNECTICUT NATU	0.0000%	8,741.628	0.5924%	0.5924%	$6,587,930
CONSOLIDATED EDIS	0.0000%	2,968.329	0.2012%	0.2012%	$2,237,014
CREOLE GAS PIPELI	0.0000%	31,747.404	2.1515%	2.1515%	$23,925,711
EAST OHIO GAS	0.0000%	1,155.787	0.0783%	0.0783%	$871,033
MOUNTAINEER GAS	0.0000%	1,498.181	0.1015%	0.1015%	$1,129,070
NASHVILLE GAS COM	0.0000%	1,400.385	0.0949%	0.0949%	$1,055,368
NAT FUEL GAS DISTR	0.0000%	2,530.807	0.1715%	0.1715%	$1,907,285
NEW JERSEY NATUR	0.0000%	3,649.632	0.2473%	0.2473%	$2,750,462
NEW YORK STATE EL	0.0000%	1,973.647	0.1338%	0.1338%	$1,487,394
NIAGARA MOHAWK P	0.0000%	4,998.135	0.3387%	0.3387%	$3,766,731
NORTH ALABAMA GA	0.0000%	2,190.093	0.1484%	0.1484%	$1,650,514
ORANGE AND ROCKL	0.0000%	2,414.642	0.1636%	0.1636%	$1,819,740
POLARIS, THE PIPELI	0.0000%	2,609.414	0.1768%	0.1768%	$1,966,526
PUBLIC SERVICE ELE	0.0000%	5,259.167	0.3564%	0.3564%	$3,963,452
SOUTHERN CONNEC	0.0000%	487.025	0.0330%	0.0330%	$367,035
UGI CORPORATION	0.0000%	2,954.273	0.2002%	0.2002%	$2,226,421
Marketer/Broker Transportation Customers					
ALATENN ENERGY M	0.0000%	1,258.393	0.0853%	0.0853%	$948,359
CATAMOUNT NATUR	0.0000%	5,673.521	0.3845%	0.3845%	$4,275,720

[1] Customer	[2] Deficiency Allocation Factors	[3] 1988 Sales & Transportation (MMcf)	[4] Volumetric Allocation Factor	[5] Difference (4-2)	[6] Cost Impact of Difference
CNG TRADING COMP	0.0000%	5,999.102	0.4066%	0.4066%	$4,521,087
DIAMOND SHAMROC	0.0000%	1,193.348	0.0809%	0.0809%	$899,340
ENERGY MARKETING	0.0000%	1,085.957	0.0736%	0.0736%	$818,407
ENTRADE CORPORA	0.0000%	7,175.159	0.4863%	0.4863%	$5,407,396
GAS SYSTEM NETWO	0.0000%	1,177.413	0.0798%	0.0798%	$887,331
GULF ENERGY MARK	0.0000%	1,117.093	0.0757%	0.0757%	$841,872
HADSON GAS SYSTE	0.0000%	10,826.937	0.7337%	0.7337%	$8,159,476
HOUSTON GAS EXCH	0.0000%	1,096.342	0.0743%	0.0743%	$826,233
INTERCON GAS, INC.	0.0000%	3,443.478	0.2334%	0.2334%	$2,595,099
LOUISIANA STATE GA	0.0000%	3,832.972	0.2598%	0.2598%	$2,888,632
NATURAL GAS CLEA	0.0000%	60,852.580	4.1239%	4.1239%	$45,860,167
PARAGON GAS CORP	0.0000%	5,002.464	0.3390%	0.3390%	$3,769,994
PNG ENERGY COMP	0.0000%	1,381.101	0.0936%	0.0936%	$1,040,835
SEAGULL MARKETIN	0.0000%	9,510.723	0.6445%	0.6445%	$7,167,541
SHELL GAS TRADING	0.0000%	1,319.355	0.0894%	0.0894%	$994,302
SNG TRADING, INC	0.0000%	2,200.865	0.1491%	0.1491%	$1,658,632
SUPERIOR NATURAL	0.0000%	2,019.181	0.1368%	0.1368%	$1,521,710
TEJAS POWER CORP	0.0000%	12,666.698	0.8584%	0.8584%	$9,545,970
TENNESSEE MARKET	0.0000%	47,106.450	3.1923%	3.1923%	$35,500,708
TENNGASCO CORPO	0.0000%	202,580.638	13.7286%	13.7286%	$152,670,304
TEXACO GAS MARKE	0.0000%	16,185.139	1.0968%	1.0968%	$12,197,563
TRANSCO ENERGY M	0.0000%	46,947.584	3.1816%	3.1816%	$35,380,982
TXG GAS MARKETIN	0.0000%	1,345.843	0.0912%	0.0912%	$1,014,264
UER MARKETING CO	0.0000%	1,282.338	0.0869%	0.0869%	$966,405

UNION TEXAS PETRO	0.0000%	12,637.345	0.8564%	0.8564%	$9,523,848
Other Transportation Customers					
BISHOP PIPELINE CO	0.0000%	4,540.642	0.3077%	0.3077%	$3,421,952
BRANDYWINE INDUS	0.0000%	2,119.958	0.1437%	0.1437%	$1,597,658
CSX INTRASTATE GA	0.0000%	3,276.703	0.2221%	0.2221%	$2,469,413
ENDEVCO OIL & GAS	0.0000%	3,349.402	0.2270%	0.2270%	$2,524,201
ENERGYNORTH, INC	0.0000%	1,054.927	0.0715%	0.0715%	$795,022
EXCEL INTRASTATE	0.0000%	5,339.761	0.3619%	0.3619%	$4,024,190
LOUISIANA GAS SYS	0.0000%	2,001.010	0.1356%	0.1356%	$1,508,016
LOUISIANA INTRASTA	0.0000%	5,420.643	0.3674%	0.3674%	$4,085,145
MINOR CONTRACTS	0.0000%	116,581.486	7.9006%	7.9006%	$87,858,993
NICOR SUPPLY INC	0.0000%	1,778.335	0.1205%	0.1205%	$1,340,202
NI-GAS SUPPLY INC	0.0000%	2,336.171	0.1583%	0.1583%	$1,760,602
NORTHERN INTRAST	0.0000%	3,976.614	0.2695%	0.2695%	$2,996,885
NYCOTEX GAS TRAN	0.0000%	1,190.793	0.0807%	0.0807%	$897,414
PROCTER AND GAMB	0.0000%	1,936.698	0.1312%	0.1312%	$1,459,549
PSI, INC.	0.0000%	7,400.815	0.5015%	0.5015%	$5,577,456
QUIVIRA GAS COMPA	0.0000%	21,513.952	1.4580%	1.4580%	$16,213,502
STELLAR GAS COMP	0.0000%	1,960.770	0.1329%	0.1329%	$1,477,690
TOTAL	100.03%	1,475,606.203	100.00%	−0.03%	($334,173)

APPENDIX H

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 88-1046

TRANSWESTERN PIPELINE COMPANY,
Petitioner

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

and Consolidated Cases

Before: Wald, Chief Judge; Mikva, Edwards, Ruth B. Ginsburg, Silberman, Buckley, Williams, D. H. Ginsburg, Sentelle and Thomas, Circuit Judges

ORDER

[Filed May 31, 1990]

The Suggestions For Rehearing *En Banc* of the respondent Commission and petitioner Transwestern Pipeline Company have been circulated to the full Court. No member of the Court requested the taking of a vote thereon. Upon consideration of the foregoing it is

ORDERED, by the Court *en banc*, that the suggestions are denied.

Per Curiam

FOR THE COURT:
CONSTANCE L. DUPRE
Clerk

By: /s/ Robert A. Bonner
ROBERT A. BONNER
Deputy Clerk

A statement of Chief Judge Wald is attached.

Separate statement of Chief Judge Wald—No. 88-1046, *et al.*

I would ordinarily call for a vote on the suggestion for rehearing *en banc.* As I noted in my dissent from the denial of the petition to rehear *en banc AGD v. FERC*, No. 88-1385 (March 30, 1990), I think the Court's current interpretation of the filed rate doctrine is overly rigid, at a time when the FERC needs latitude to navigate the recent dramatic changes in the structure of the natural gas industry. However, the decisive vote against rehearing *en banc* in *AGD v. FERC* convinces me that to call for a vote for rehearing *en banc* in this case would be equally futile. It remains for the Supreme Court to settle this important question of how impenetrable a barrier the filed rate doctrine is to FERC's efforts at allocating the inevitable burdens stemming from fundamental readjustment of the pipeline industry.

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 88-1046

TRANSWESTERN PIPELINE COMPANY,
Petitioner

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

and Consolidated Cases

Before: Williams, D. H. Ginsburg and Sentelle, Circuit Judges

ORDER

[Filed May 31, 1990]

Upon consideration of the petitions for rehearing of the respondent Commission and petitioner Transwestern Pipeline Company, it is

ORDERED, by the Court, that the petitions are denied. Neither the Commission nor Transwestern raised in their briefs the argument that Transwestern's filing in December 1987 gave notice that the customers would be charged the remaining balance in Account No. 191 in the event all customers left the system. We therefore did not and do not address it. See *Carducci* v. *Regan*, 714 F.2d 171, 177 (D.C. Cir. 1983).

Per Curiam

FOR THE COURT:
CONSTANCE L. DUPRE
Clerk

By: /s/ Robert A. Bonner
ROBERT A. BONNER
Deputy Clerk

APPENDIX I

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Nos. 88-1385, *et al.*

ASSOCIATED GAS DISTRIBUTORS, *et al.*,
Petitioners

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

MOTION FOR STAY OF MANDATE PENDING
APPLICATION FOR A WRIT OF CERTIORARI

Pursuant to Rule 41(b) of the Federal Rules of Appellate Procedure and Local Rule 15(b), the Federal Energy Regulatory Commission (Commission) moves this Court for a stay of the mandate in the above-captioned cases for 90 days (but no less than 30 days), pending consultation with the Solicitor General and his action on the Commission's request that he authorize the filing of a petition for writ of certiorari in these cases.

STATEMENT

In an Opinion issued on December 28, 1989, *Associated Gas Distributors* v. *FERC*, 893 F.2d 349 (D.C. Cir. 1989), this Court vacated and remanded orders of the Commission on the ground that the deficiency based allocation methodology used in this case violated the filed rate doctrine.[1] Timely petitions for rehearing, and sug-

---

[1] That is, *Tennessee Gas Pipeline Company*, Docket Nos. RP86-119-000, *et al.*, 42 FERC ¶ 61,175 (1988); 42 FERC ¶ 61,329 (1988);

gestions for rehearing *en banc*, were filed by the Commission and numerous other parties.

On March 30, 1990, this Court denied the applications for rehearing and suggestions for rehearing *en banc*. Three judges would have voted to hear the case *en banc*.

ARGUMENT

THE COURT SHOULD ISSUE A STAY OF THE MANDATE AS HERE REQUIRED SINCE THE CRITERIA WARRANTING SUCH ACTION ARE CLEARLY SATISFIED

This Court has held that when substantial legal issues are presented, there "exists good cause to justify staying the mandate pending disposition of the petitions [for writ of certiorari]." *Deering Milliken, Inc.* v. *FTC*, 647 F.2d 1124, 1128 (D.C. Cir. 1980). In such a case, the Court has further noted, "a stay [of the mandate] would be available merely for the asking." *Id.* An important consideration in this regard is the maintenance of the *status quo* while the Supreme Court considers the merits of petitions for writ of certiorari. *Dayton Board of Education* v. *Brinkman*, 439 U.S. 1358 (1978) (Rehnquist, Circuit Justice). And a stay is particularly appropriate where, in its absence, the judgment under review would "have a major impact country wide * * *", *NCAA* v. *Board of Regents*, 463 U.S. 1311, 1313 (1983) (White, Circuit Justice). These requirements are clearly met here.

A. To start with, these cases raise significant questions, in the Commission's view, warranting Supreme Court review as to the scope and proper application of

---

44 FERC ¶ 61,039 (1988); 44 FERC ¶ 61,155 (1988); 44 FERC ¶ 61,330 (1988); 44 FERC ¶ 61,401 (1988); 45 FERC ¶ 61,431 (1988); 46 FERC ¶ 61,021 (1989); 46 FERC ¶ 61,156 (1989); and 46 FERC ¶ 61,344 (1989).

the "filed rate doctrine", a statutory-based rule that accords effect to the rate which is on file with the Commission. Here, the Court held that the doctrine was violated because the method of cost allocation adopted by the Commission for payment of current costs took account of past purchasing practices. The Commission disagrees with this ruling.

In its view, the filed rate doctrine was not violated here. First, the regulated utility gave the requisite 30 days notice, under Section 4(d) of the Natural Gas Act, 15 U.S.C. § 717c(d), of its intent to place a new rate containing currently incurred costs in effect; second the Commission, acting under Section 4(d) and Section 5(a) of the Act, 15 U.S.C. § 717d(a), thereafter placed the new rate into effect prospectively. In these circumstances —where current costs are allocated as a measure of each customer's take or pay responsibilities based on past purchasing practices—the Commission respectfully submits that its reading of the controlling statutory language is consistent with the analysis of that doctrine as developed by the Supreme Court. *Montana-Dakota Utilities Co.* v. *Northwest Pipeline Service Co.*, 341 U.S. 246 (1951); *Arkansas Louisiana Gas Co.* v. *Hall*, 453 U.S. 571 (1981).

The Court's ruling, on the other hand, results in an excessively rigid interpretation which fails to take account of the long established principle of ratemaking that cost incurrence should attempt to track cost responsibility; as a result, its ruling in this case could seriously hamper the Commission's effort to comply with this Court's remands in *AGD I*, *supra*, and *American Gas Association* v. *FERC*, 888 F.2d 136 (D.C. Cir. 1989). *See*, Statement of the Judges who would have granted rehearing *en banc* in *AGD II* at slip pages 1-2.

In sum, entry of a stay of the mandate pending Supreme Court review is appropriate in the present con-

text because of the significant issues involved.[2] *See e.g., Commodity Futures Trading Commission* v. *British American Commodity Options Corp.*, 434 U.S. 1318, 1320 (1977) (Marshall, Circuit Justice).

B. The need for the stay is reenforced where, as here, the Court's mandate promises to have far-ranging industry disclocation. *NCAA* v. *Board of Rights, supra.* There can be no dispute that almost three billion dollars has already been passed through under the purchase deficiency allocation methodology, which this Court has held to violate the filed rate doctrine.

If the mandate is now issued by this Court, the Commission will likely have to seek voluntary remands of the fifty other cases being held in abeyance. Once those cases are remanded, the Commission will have to consider whether and how to establish procedures for refund by the numerous pipelines of the money collected by pipelines from their customers under the purchase deficiency mechanism. In addition, the Commission would then be required to consider another method, if any, by which interstate pipelines would have a reasonable opportunity to recover these monies.[3] Untangling which customers might be owed refunds and which customers might owe payments—the reallocation of billions of dollars of take or pay payments—entails a significant administrative undertaking.

But at the same time, the Commission is seeking authorization from the Solicitor General to file for Supreme

---

[2] In addition, a substantial question of deference arises since the filed rate doctrine derives from the statutory language of the Natural Gas Act, the Commission's organic statute. *See Chevron, U.S.A., Inc.* v. *NRDC, Inc.*, 467 U.S. 837 (1983). *See K Mart Corp.* v. *Cartier, Inc.*, 486 U.S. 281 (1988).

[3] Indeed, motions have already been filed with the Commission seeking action which would cease the continuing assessment of take-or-pay liabilities under the purchase deficiency mechanism.

Court review. If such authorization is granted, review of the decision of this Court before the United States Supreme Court is likely.[4] In such circumstances, the status quo is necessary to avoid significant and unwarranted disruption and confusion in the natural gas industry.

Failure to grant a stay would be particularly disruptive to the industry were the Supreme Court to reverse the decision of this Court, and rule that the filed rate doctrine was not breached by the Commission's method of allocation. The more reasoned path, we submit, would be for this Court to grant a stay so that final appellate review may be sought in an atmosphere free of such confusion and disarray. See *Mobil Oil Exploration and Producing Southeast Inc.* v. *FERC*, 885 F.2d 209 (5th Cir. 1989), pending a petition for a writ of certiorari, *sub nom. Federal Energy Regulatory Commission* v. *United Distribution Companies*, S. Ct. No. 89-1453, where the Supreme Court granted a stay on claims as here that industry wide disorder would likely result from any change in the regulatory *status quo*. See also, *CFTC* v. *British American Commodity Options Corp.*, 434 U.S. 1316, 1320 (1977) (Marshall, J. in Chambers) (declining to vacate a stay that "merely preserves the regulatory status quo pending final action by this Court").

The real potential for chaos is underscored by the enormous sums of money—$30 to 40 billion dollars—involved in the instant case and the other cases pending in abeyance. To illustrate, if Tennessee is required to refund the monies previously collected under the purchase deficiency method (some $600 million), it must immediately find a new method of allocation by which to recover these monies. This disruption, moreover, will distort significantly the market signals that the Commission

---

[4] The Commission is also advised that Tennessee and others involved in the case will also seek a stay and file petitions for writ of certiorari.

believes that customers need to determine whether or not to purchase gas on a day-to-day basis.

C. In sum, in the Commission's view, the more efficient route to follow in this case is to retain the status quo by staying the mandate, and permitting the Supreme Court to examine the substantial issues raised by this case. If the Supreme Court reverses this Court, then pass through under the purchase deficiency method will continue. On the other hand, if the Supreme Court affirms the decision of this Court, or denies petitions for writs of certiorari, the Commission will be required to develop a new pass through methology.

CONCLUSION

For the foregoing reasons, the Commission submits that a stay of the mandate for a period of 90 days (but no less than 30 days) should be granted to allow the Commission to consult with the Solicitor and take all necessary steps for the filing of a timely petition for a writ of certiorari.

Respectfully submitted,

WILLIAM S. SCHERMAN
General Counsel

/s/ Jerome M. Feit
JEROME M. FEIT
Solicitor

JOEL M. COCKRELL
Attorney

Federal Energy Regulatory
Commission
Washington, D.C. 20426
(202) 357-8177

April 3, 1990

JMC:dln

APPENDIX J

The following is a list of parties to this proceeding.

Alabama-Tennessee Natural Gas Company
American Iron & Steel Institute
American Paper Institute, Inc.
ARCO Oil & Gas Company
Arkla, Inc.
Associated Gas Distributors
Baltimore Gas and Electric Company
The Berkshire Gas Company, *et al.*
The Brooklyn Union Gas Company
Cabot Corporation
Central Hudson Gas & Electric Corporation
Chattanooga Gas Company
City of Clarksville
City of Portland
City of Springfield
CNG Transmission Corporation
Columbia Gas Distribution Companies
Columbia Gas of Kentucky, *et al.*
Columbia Gas Transmission Corporation
Connecticut Natural Gas Corporation
Consolidated Edison Company of New York, Inc.
Dayton Power & Light Company
East Tennessee Group
Equitable Gas Company
Federal Energy Regulatory Commission
Humphrey's County Utility District
The Inland Gas Company, Inc.
Long Island Lighting Company
Maryland Peoples' Counsel
Nashville Gas Company
National Fuel Gas Supply Corporation
New York State Electric and Gas Corporation
Niagara Mohawk Power Corporation
North Carolina Utilities Commission
North Penn Gas Company

Northern Illinois Gas Company
Northern Indiana Public Service Commission
Office of the Consumers' Counsel, State of Ohio
Orange and Rockland Utilities, Inc.
Pennsylvania Gas & Water Company
Pennsylvania Public Utilities Commission
Peoples Gas Light and Coke Company
Peoples Natural Gas Company
Process Gas Consumers Group, *et al.*
Public Service Electric and Gas Company
Rochester Gas and Electric Company
Shell Offshore, Inc. & Shell Western E&P
Southern Natural Gas Company
Tennessee Gas Pipeline Company
Tennessee SGS Customer Group
Texas Eastern Transmission Corporation
Transcontinental Gas Pipeline Corporation
United Gas Pipe Line Company
Washington Gas Light Company, *et al.*
Western Kentucky Gas Company